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CO_2 EMISSIONS: PERSPECTIVES AND FUTURE OPTIONS FOR CANADIAN ELECTRIC UTILITIES AND THE COAL INDUSTRY VOLUME I: STUDY REPORT

Prepared by:

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Association canadienne de l'électricité
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and the

COAL RESEARCH AND DEVELOPMENT SUB-COMMITTEE
of the
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CO_2 EMISSIONS: PERSPECTIVES AND FUTURE OPTIONS FOR CANADIAN ELECTRIC UTILITIES AND THE COAL INDUSTRY

VOLUME I: STUDY REPORT

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STUDY BACKGROUND

The CEA R & D Advisory panel on Flue Gas Emission Controls has directed its primary efforts towards SO_2 and NOx reductions. With the concerns expressed on global warming and the possible contribution of CO_2, they decided to investigate the technical options available to utility combustion processes. For the benefit of utility personnel, the scope was expanded to provide a basic understanding of the issues associated with the greenhouse effect.

The IPACE Coal R & D Coordinating committee was preparing specifications for its own study, on the impact that CO_2 reductions would have on the Coal Industry. Since the electric utilities are the industries' main market, and since many of the topics were similar, it made sense to integrate the two studies.

This was an exploratory study, and it should be reviewed as such. It represents a consultant's assessment of many complex issues, carried out over a very limited time period. Therefore, the study should not be interpreted as reflecting policy positions of the sponsoring organizations.

ABSTRACT

This report provides a background to the global warming phenomenon with respect to CO_2 emissions. The impact of climate change on Canadian electric utilities is assessed. In light of ongoing international policy and legislative action scenarios, it reviews the technical options available to electric utilities and how the Canadian coal industry may be affected.

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Executive Summary

The Global Warming Phenomenon

The greenhouse effect is a natural heat-trapping mechanism without which the average temperature of the earth would be about -19°C instead of the observed 15°C. There is concern among the majority of climatologists that the measured increase of greenhouse gas concentrations in the atmosphere could produce major climatic changes over the next several decades.

There are several greenhouse gases, of varying atmospheric concentrations and heat-trapping strengths on a molecule-per-molecule basis. The concentration of carbon dioxide (CO_2) has increased from about 280 ppmv in 1800 to 350 ppmv in 1988, and is continuing to increase at about 1.2 ppmv per year. Strong correlation exists between this trend and human activity. CO_2 is responsible for 50% to 60% of the contribution of greenhouse gases to global warming since the industrial revolution. It will also be the dominant contributor to further increases in the greenhouse effect.

Climatic Change and Impact on Electric Utilities

Much uncertainty remains in assessing both the historical record and the climatic response to a given build-up of greenhouse gases. There are good reasons for confidence in computer model projections of the global scale climatic response to increasing greenhouse gas concentrations, but the models also have important limitations.

Computer models tend to agree on globally and east-west averaged projections of climatic change. If the projections are correct, the average temperature of the earth could rise to as much as 2.5°C above the global mean of the 1980's by 2050. Agreement on regional projections is poor, but warming magnitudes and warming rates in higher latitude countries such as Canada could be 2 to 3 times greater than the average. Mean winter temperatures are expected to rise more than mean summer temperatures.

A changing climate is unlikely to produce weather conditions beyond the operating experience of Canadian utilities. Planners and engineers should, however, begin to allow for the possibility that climatic data could change significantly within the planning horizons and the design lifetimes of utility system operations. The possible impacts associated with a changing climate are comparable to other risks and uncertainties faced by utilities.

A climatic warming would directly affect hydraulic generating capacity; electricity demand by heating and cooling equipment; power transmission and distribution systems; and the efficiency of thermal generating units.

Utility system operations in Manitoba and Saskatchewan would probably be impacted most by a climatic warming. With warming, temperatures are expected to become less variable in the Prairies, but precipitation would be more variable. Preliminary studies suggest that Ontario and Québec will be less affected. Little study has been made to date of how a climatic warming might impact on other regions of Canada.

Policy Assessment

The June 1988 Toronto Conference on The Changing Atmosphere called for a 20% reduction of annual global CO_2 emissions from 1988 levels by 2005. Several international declarations on the greenhouse effect were made in 1989. These included the Hague Declaration and the G-7 Summit Final Communiqué; Canada is signatory to both.

The main international body assessing the scientific evidence of climatic change and for developing possible policy responses is the Intergovernmental Panel on Climatic Change (IPCC), sponsored by the United Nations (UN). The IPCC will report to the UN General Assembly and to the Second World Climate Conference in November, 1990.

A convention on climatic change could be convened by the UN as early as 1992. In the case of CFC reduction measures, the Montréal Protocol followed only

two years after the 1985 Vienna Convention for Protection of the Ozone Layer. Domestic measures were enacted after a further two years.

The focus of Canadian government activity is the Task Force on Energy and the Environment, established in August 1988 by the Federal, Provincial and Territorial Energy Ministers. No definitive timetable can be estimated for CO_2 regulatory reforms in Canada, but the pace will likely be intensive compared to traditional time frames. The timetable for the Ontario MISA initiative covers about a six year period from initial consultation to the deadline for compliance with a limits regulation.

Most industrializing countries show no interest in responding to the build-up of greenhouse gases in any way that might interfere with their economic growth. Many nations, such as the USSR and Eastern European countries, also face serious and widespread air and water pollution problems.

Canadian Electrical Energy and the Coal Industry

Under even extreme assumptions, scenarios of future global energy demand show that the world cannot meet its projected energy needs over the next century without using coal.

Canada has abundant energy resources of hydroelectricity, uranium, petroleum and coal. Canadian coal reserves, mainly located in Western Canada, are large and of great economic importance to Canada.

Electricity production in Alberta, Saskatchewan and Nova Scotia is largely based on coal combustion. British Columbia, Manitoba, Québec and Newfoundland rely almost completely on hydroelectric resources. New Brunswick generates electricity from nuclear, oil and (to a lesser extent) coal. Ontario has roughly equal proportions of fossil, hydroelectric and nuclear energy.

Canada meets two thirds of its electrical energy needs using hydroelectric power alone. Fossil fuel units generate only about one fifth of Canadian electrical energy. Utility projections of electricity demand are for an

overall growth to 2005 of 2.2% per year.

The Canadian coal industry employed a direct work force of some 12,000 people in 1988, with a total revenue in excess of $2 billion. Coal production in 1988 was 71 megatonnes (Mt), of which 32 Mt was exported. Coal consumption in Canada was 54 Mt in 1988, 85% of which was used to generate electricity. About 17 Mt of mainly metallurgical coal was imported by Ontario from the USA. Industrial coal usage was fairly constant in the 1980's.

Canadian coal exports are primarily from British Columbia metallurgical coal mines, directly employing some 5,000 people, and aimed mainly at the Japanese market. Key growth areas are Brazil and the Pacific Rim countries of Korea and Taiwan.

World demand for metallurgical coal imports is now about 160 Mt per year; growth projections for the coming decade range from 5% to over 15%. World thermal coal import demand was 176 Mt in 1986, and projections call for significant growth to perhaps 300 Mt by 2005. Competition from other coal exporting nations is keen, but Canada should be able to at least maintain present exports of metallurgical coal, and increase thermal coal exports by 3% to 5%.

CO_2 Emissions in Perspective

Global CO_2 emissions from fossil fuels are currently about 20 Gigatonnes (Gt) per year, and could rise to 70 Gt per year by 2050. The USA and the USSR each contribute about one fifth to the present total. Canadian CO_2 emissions from all sources were about 0.47 Gt in 1988 (2% of the global total), and at present are projected to be between 0.6 Gt and 0.7 Gt by 2005.

Provincial (direct combustion) emissions of CO_2 in 1987 from all sources were:

	(Mt)	%
Ontario	154	33
Alberta	105	22
Québec	64	14
B.C.	61	13
N.S.	17	4
N.B.	14	3
Saskatchewan	31	6
Others	25	5
	471	

Provincial CO_2 emissions vary greatly both in total and in those sectors responsible for the emissions. In some provinces large quantities of CO_2 are also emitted from industrial, residential and other sources. Transportation accounts for 30% of all Canadian CO_2 emissions, but industrial CO_2 emissions are not large except locally:

	% of Canadian Total CO_2 Emissions
Steel Industry	Less than 4%
Cement and Ammonia Industries	Less than 2%
Pulp and Paper Industry	About 7%.

Electric utilities contribute about a quarter (0.12 Gt) of all Canadian CO_2 emissions. This estimate includes mark-ups to the full fuel life cycle, to account for emissions during transportation and mining.

Technology Assessment

The main fossil-based technology/fuel options available for in-service dates to 2005 are:

- Conventional Steam (coal, oil, gas);
- Cogeneration plants;
- Integrated Gasification Combined Cycle (IGCC);
- Fluidized Bed Combustion (FBC); and
- Gas Turbines.

No new technology offers a clearly most cost-effective way to reduce CO_2 emissions. Factors such as the control of SO_2, NO_x and particulate emissions must also be considered in selecting technology and fuel options.

Cogeneration plants, in which electricity generation is combined with the use of heat by an industrial process, offers the best potential for CO_2 emission reduction.

Using coal, the emission of CO_2 can be reduced using clean coal technologies such as IGCC, but only to the limited degree that the higher efficiencies of the processes allow.

Using gas can significantly reduce the emission of CO_2 compared to coal, but the availability and cost of gas are key concerns which must be addressed.

For the steel industry, the Midrex process and cokeless cupolas offer reduced CO_2 emissions, but again will not be considered favourably by the industry unless the supply and price of natural gas can be guaranteed.

Recovery of CO_2 requires additional energy. Usage or disposal must prevent subsequent release of the CO_2 to the atmosphere. There is some potential in Alberta and Saskatchewan for disposal of CO_2 through Enhanced Oil Recovery and similar operations. Other disposal options do not appear to be economically feasible, and could have adverse environmental impacts.

Non-fossil utility scale generating options available by 2005 are mainly hydroelectric power; the new CANDU 3 nuclear reactor; tidal power; and purchasing "clean" power from other utilities.

Comparative capital and electricity production costs of the main fossil technology/fuel options are given in Section 7 of this report. Costs for non fossil and other options (energy storage, for example) are given in the Appendices to Section 7.

Legislation Action Scenarios and Planning Options

Two scenarios of legislative action to reduce anthropogenic CO_2 emissions are considered by this study. Scenario I corresponds to the call to action of the June 1988 Toronto Conference:

Scenario I: Reduce CO_2 emissions by 20% of 1988 levels by 2005; and
Scenario II: Hold CO_2 emissions to the 1988 base level by 2005.

Applying the scenarios to total Canadian CO_2 direct combustion emissions, the required reductions from all provinces and sectors would be approximately:

Source	Projected 2005 CO_2 emission (Mt)	---- Reductions (Mt) ---- Scenario I	Scenario II
NEB (low)	598	220	125
NEB (high)	649	271	176
EMR	706	328	233

where the National Energy Board (NEB) low and high energy use scenario projections are considered to be at least as credible as the Energy, Mines and Resources (EMR) Inter-Fuel Substitution Demand (IFSD) model projection.

Applying the scenarios to electric utility full fuel cycle emissions only, the required CO_2 cuts from present projections of 2005 emissions (Mt) are:

	Utility CO_2 Emissions 1988	2005	--------Reductions-------- Scenario I	Scenario II
Ontario	39.1	39.1*	7.8	0.0
Alberta	47.5	74.0	36.0	26.5
N.S.	8.5	15.1	8.3	6.6
N.B.	7.7	15.2	9.0	7.5
Saskatchewan	14.1	19.7	8.4	5.6
Others	5.0	12.7	8.7	7.7
	121.9	175.8	78.2	53.9

* An additional 10.7 Mt of CO_2 is estimated from a preliminary assessment of Ontario Hydro's Demand/Supply plan.

Scheduling of the legislative scenarios is an important consideration. Coal

industry and electric utility operations and projects are often capital intensive; they are characterized by long planning periods and considerable economic inertia.

The continued use of coal is critically important to several utilities as they plan to meet future increases in electrical energy demand. Alternative means of generating electricity are not readily available in many cases. Conversely, local electricity generation constitutes the only market for thermal coals in many areas.

Utilities in Alberta, Saskatchewan, New Brunswick and Nova Scotia would face the most difficult planning challenges if legislative action is implemented. The socio-economic impacts of the above legislative scenarios would also extend to support industries such as the transportation sector.

Unilateral CO_2-related legislative action by Japan or by other Pacific nations would primarily impact mines in British Columbia. Such action is unlikely, however, due to the positions of the governments concerned.

A realistic selection of fossil technology/fuel options to minimize CO_2 emissions is applied step-by-step in Section 8 to the main fossil-using regions of Canada. Scenario I can only be met by regional utilities if all the coal-fired and oil-fired power stations in Canada are converted to gas-fired steam generators. It would also be necessary to substitute gas turbine-combined cycle units using natural gas for all planned coal-fired unit additions.

Even such drastic action by Canada would, however, have little effect on the build-up profile of atmospheric CO_2 if it is applied unilaterally. This is not a recommendation to do nothing, but a recognition that an international and broad-based response is needed if the build-up is to be significantly slowed.

A need for inter-provincial co-operation is indicated. In order to be most effective, CO_2 emission reductions should also come from transportation and other non-utility sectors. Even so, it is clear that there will come a point beyond which it is more cost effective to assist others in their efforts to reduce CO_2 emissions from fossil fuels than to attempt further reduction of Canadian CO_2 emissions.

Utilities can also reduce CO_2 emissions through demand-side options such as promoting energy efficiency and conservation. Broader options could aim to offset CO_2 emissions from Canadian sources by reducing CO_2 emissions elsewhere. These options include exporting Canadian hydroelectric power to the USA, funding reforestation projects and technology transfer to industrializing nations.

Research and Development Recommendations

R & D of technologies and fuels to reduce CO_2 emissions should focus on:

- Determining the suitability of Western Canadian coals for gasification, including coal preparation and sizing;
- Pilot plant demonstration of IGCC gasification and FBC processes in key coal areas;
- Collaborating with industry and others to identify major Canadian cogeneration opportunities;
- Pilot plant demonstration of a natural gas phosphoric acid fuel cell process; and
- Improving molten carbonate, solid polymer and other fuel cells.

CO_2 emission evaluation should be included in R & D work relating to SO_2, NO_x and other emission control limits. The USA clean coal work should also be monitored, and R & D programmes shared in where appropriate.

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UNITS AND SYMBOLS

kW	Kilowatt (10^3 Watts)
MW	Megawatt (10^6 Watts)
GW	Gigawatt (10^9 Watts)
TW	Terawatt (10^{12} Watts)
Mt	Megatonne (10^6 tonnes)
PJ	Petajoule (10^{15} Joules)
kWh	Kilowatt-hour (1 kW of power applied for 1 hour)
ppmv	Parts per million by volume

ΔQ Globally averaged change in heat-trapping strength (W m^{-2}).

ΔT_{2x} Equilibrium mean annual globally averaged surface air temperature change (°C) in response to doubling the concentration of atmospheric CO_2.

1 tonne of Carbon (C) combines with oxygen to produce 3.67 tonnes of Carbon Dioxide (CO_2)

Acronyms

CTU	Combustion (Gas) Turbine Unit
EOR	Enhanced Oil Recovery
FBC	Fluidized Bed Combustion (several types)
FGD	Flue Gas Desulphurization
IGCC	Integrated Gasification Combined Cycle
NUG	Non Utility Generator
PAFC	Phosphoric Acid Fuel Cell

1.0 INTRODUCTION

In June 1988, Canada hosted the First World Conference on "The Changing Atmosphere: Implications for Global Security". The Conference Statement was endorsed by over 300 scientists and policy makers from 46 countries. It called for the development of energy policies to reduce the emission of carbon dioxide (CO_2) and other trace gases; and for a reduction of global CO_2 emissions by 20% of 1988 levels by the year 2005.

This study examines, with a focus on the period to 2005:

- The global warming phenomenon, climatic change projections for Canada, and possible impacts on utility system operations;
- Policy directions and legislative action timetables;
- Canadian electrical energy and the coal sector;
- Canadian utility CO_2 emissions from various perspectives;
- Existing and emerging supply-side technology/fuel and other options to reduce CO_2 emissions;
- The impact of legislative action scenarios on Canadian electric utilities and on the coal industry;
- Planning options which can be brought to bear before 2005; and
- Recommendations for Research and Development.

Several areas addressed are fast-changing. This must be borne in mind when reading this report. Information on present planning of major utilities was solicited, when available, through questionnaires.

2.0 THE GLOBAL WARMING PHENOMENON

The global climate is governed by many factors, primarily the distribution of absorbed incoming solar radiation and the dynamic effects of the earth's rotation. Climatic changes involve complex interactions between incoming solar radiation, outgoing terrestrial radiation, the earth's atmosphere, oceans, crust, biosphere, ice and snow. Interaction time scales range from seconds to thousands of years.

Climatic statistics are computed over a 30 year period following the definition established by the World Meteorological Organization. Two regions may have the same average annual or seasonal rainfall, for example, but they have different climates if one area is subject to greater variation of rainfall.

2.1 The Greenhouse Effect

The greenhouse effect is a natural heat-trapping mechanism which accounts for about 34°C of the average temperature of the earth (15°C). It arises because certain trace gases in the atmosphere are largely transparent to incoming solar radiation, but partially absorb infrared radiation that would otherwise escape to space. The earth's mean temperature depends on the balance between outgoing infrared radiation and absorbed solar radiation.

The principal greenhouse gases are as follows, in decreasing order of importance and with estimated atmospheric residence times (Graedel and Crutzen, 1989):

Greenhouse Gas		Atmospheric Residence Time
Water Vapour	(H_2O)	8 days
Carbon Dioxide	(CO_2)	100 years
Surface Ozone	(O_3)	days
Methane	(CH_4)	10 years
Chloroflourocarbons	(CFC's)	60 to 100 years
Nitrous Oxide	(N_2O)	170 years

The deep ocean (below the mixing depth) is the main sink for CO_2. The upper ocean (above the mixing depth) and the atmosphere respond almost as a single unit to CO_2 emissions to the atmosphere, with a CO_2 turnover time between the two on the order of 1 to 10 years. The rate at which CO_2 is transferred to the deep ocean is much slower, however, hence the long atmospheric (and upper ocean) residence time for CO_2.

The low atmospheric residence time of water vapour explains why acid rain is a more localized problem than the build-up of CO_2. Fluxes of water vapour from anthropogenic sources are completely negligible in comparison to natural fluxes in the hydrological cycle (see Appendix A6-4).

Table 2-1 shows greenhouse gas concentrations in 1985, increases from 1975 to 1985, and the relative greenhouse strength of each gas on a molecule-per-molecule basis (see Lashoff and Tirpak, 1989).

The initial change in the strength of the heat-trapping mechanism due to a change in greenhouse gas concentrations (C_1 to C_2) is the best known quantity in the chain of events leading to a new climatic equilibrium. It is referred to as the change in mean global radiative forcing, ΔQ. In the case of CO_2, ΔQ varies logarithmically with concentration:

$$\Delta Q = A \ln [C_1/C_2] \qquad \text{where A is a constant}$$

Table 2-2 gives the changes due to the increase of individual greenhouse gases from pre-industrial times to 1980, and for a doubling of these gases (Ramanathan et al., 1987; Wigley, 1986). CO_2 is responsible for 50% to 60% of the total forcing increase since the industrial revolution, depending on the time interval assessed. Doubling the atmospheric concentration of CO_2 results in a change in radiative forcing of about 4.2 W m^{-2}. By comparison, the average global absorption of solar radiation is about 240 W m^{-2}.

TABLE 2-1: GREENHOUSE GAS CONCENTRATIONS AND STRENGTHS

Gas	1985 conc. (ppmv)	1975-85 increase (ppmv)	Relative Strength per molecule
CO_2	340	15	1
CH_4	1.2	0.17	30
N_2O	0.28	0.01	160
CFC's	0.0006	0.0003	17,000
Surface O_3	0.02-0.08	variable	uncertain

TABLE 2-2: GREENHOUSE GAS CONTRIBUTIONS TO THE HEAT TRAP

Gas	Pre-industrial to 1980 Forcing Change	Concentration Change	Resulting Forcing Change
CO_2	1.17 W/m^2	Double	4.2 W/m^2
CH_4	0.46	Double	0.69
N_2O	0.07	Double	0.77
CFC's	0.17	Double	0.21
Surface O_3	0.15 ?	+ 25%	0.4 to 0.5

TABLE 2-3: PROJECTED GREENHOUSE GAS CONTRIBUTIONS TO WARMING

Gas	Concentration in 2050 (ppmv)	Forcing Increase 1980 to 2050 ($W\ m^{-2}$)	Relative Contribution
CO_2	500 to 1000	2.3 to 6.5	56 to 91%
CH_4	2 to 3	0.2 to 0.6	3 to 18%
N_2O	0.35 to 0.47	0.1 to 0.4	2 to 12%
CFC's	N/A	0.2	3 to 7%
Surface O_3	N/A	0.1 to 0.6	2 to 18%

Table 2-3 shows projected greenhouse gas concentrations in 2050 for unrestricted emissions, and the corresponding increase of radiative forcing from a 1980 base, computed using Wigley's (1988) model. It is assumed that CFC production ends by 2003 and that CFC replacements are not important greenhouse gases. The radiative forcing due to surface O_3 is assumed to be 0.5 to 1.0 times that due to CH_4. For any combination of the greenhouse gas increases given on Table 2-3, CO_2 remains the dominant greenhouse gas.

A range of climatic feedback mechanisms, discussed in Appendix A2-1, can amplify or dampen the response of the climate to forcing increases. There are also a number of feedbacks involving atmospheric chemistry and the carbon cycle. The role of these mechanisms is the largest source of uncertainty in predicting climatic change. If the climate warms, for example, the melting of ice and snow will allow greater absorption of solar radiation and hence further warming. This is a positive feedback. At the same time, the rising liquid water content of cumulus and stratus clouds will increase their reflectivity (albedo). Less solar radiation would penetrate to the lower atmosphere, damping the warming. This is a negative feedback.

For present computer models, the projected final (equilibrium) change in the average surface air temperature (°C) of the earth, due to a given change in greenhouse gas concentrations, is roughly given by dividing the total change in radiative forcing ($W\ m^{-2}$) by a factor of 1 to 2.

2.2 The Observed Record

Measuring global trends of temperature and precipitation is complicated by incomplete spatial coverage and by changes in:

- Instruments, exposure, and location;
- Observation time and methods of processing data; and
- Urbanization.

A number of analyses indicate that the globally averaged surface air temperature has increased by 0.5 ± 0.2°C during the past 100 years. Figure 2-1 compares global and hemispheric surface air temperature changes (Hansen and Lebedeff, 1987; and Jones et al., 1986). This warming trend was interrupted by a cooling between 1940 and 1960 globally, and between 1940 and 1980 in the Northern Hemisphere. Other features of Figure 2-1 include:

- Greater temperature changes (warming or cooling) in the Arctic and Antarctic than at lower latitudes up to 1970;
- Greater higher latitude temperature change in winter than in summer up to 1970; and
- More pronounced warming in tropical latitudes, with little zonally averaged warming in the Arctic since the early 1970's.

Analyses of upper air temperatures and of sea surface temperatures also indicate a mean global warming during the past century. Recent studies conclude in addition that the global mean sea level has risen by 24 ± 9 cm over the past century. Further discussion is provided in Appendix A2-2.

Figure 2-2 shows trends in atmospheric concentrations of CO_2, CH_4 and N_2O (Pearman et al., 1986; Bolle et al., 1986; and Neftel et al., 1985). Direct and continuous instrumental measurements of CO_2 did not begin until 1958, and much later for CH_4 and N_2O. Indirect approaches to extending these measurements are reviewed in Appendix A2-3. The key points are that:

- CO_2 has steadily increased from about 280 ppmv in 1800 to 315 ppmv in 1958 and 350 ppmv by 1988, with a recent rate of increase of 1.2 ppmv per year (Conway et al., 1988);

- CH_4 has increased from 0.7 ppmv in 1700 to 1.55 ppmv in 1976 and 1.72 ppmv in 1985, with a recent increase of 1% per year; and

- N_2O has increased from a level of 0.287 ppmv in 1900 to 0.303 ppmv in 1979 and 0.309 ppmv in 1986, with a recent rate of increase of 0.2% to 0.3% per year.

Natural fluxes of CO_2 between the land, oceans and atmosphere are generally much larger than those fluxes due to human activities. Nevertheless, it is estimated that about half of the CO_2 emitted by fossil fuel combustion over the past century has remained in the atmosphere. The global carbon cycle and associated feedbacks are discussed further in Appendix A2-4.

The greenhouse strength of CH_4 is about 30 times that of CO_2 on a molecule-per-molecule basis, as assumed by this study. Indirect atmospheric chemistry effects could increase this in the future to a factor of 70.

Atmospheric concentrations of CFC's have increased over the past 40 years from zero to their present levels (chlorine atom concentrations in the stratosphere are about 0.003 ppmv). Surface and mid-air O_3 concentrations have also increased significantly over much of the Northern Hemisphere, by some 5% in the 1970's alone (Ramanathan et al., 1987).

2.3 The Scientific Basis of Concern

The warming of the past century does not stand out as being climatologically unusual. Climatic warming rates comparable to that of the past 100 years have probably occurred at other times during the past 1,000 years, with periods when the climate was warmer than in recent decades. There is no simple or consistent correspondence so far between observations and model-predicted patterns of climatic change.

Many processes which influence climatic response are not included, or are only poorly represented in present computer models. Examples include the effect of cloud feedbacks and of internal oscillations in the deep ocean. Appendix A2-6 discusses the discrepancies between computer model results and observations.

Several mechanisms in addition to variations in greenhouse gas concentrations can cause climatic change on timescales of decades to centuries. Such factors have clearly contributed to climatic change over the past century. Examples include variations in solar output and volcanic eruptions.

A 0.5% variation in solar flux (five times larger than that observed during the most recent sunspot cycle) corresponds to a change in radiative forcing of about $\Delta Q = 1.2$ W m^{-2}. The build-up of greenhouse gases in the atmosphere has resulted in a change in forcing of about $\Delta Q = 2.2$ W m^{-2} since the industrial revolution (Table 2-2). If variations in solar output during sunspot cycles can influence climate, then greenhouse gas concentration changes must have an even larger effect (Levi, 1990). Appendix A2-7 further discusses the issue of scientific uncertainty.

It is on the basis of strong confidence in theoretical climatic projections that scientists are concerned about the continuing build-up of greenhouse gases in the atmosphere, particularly CO_2. There is little doubt that this build-up is due to human activity (see Appendix A-5). There is reason to believe, based on principles of thermodynamics, that the observed build-up has contributed at least in part to the warming. Because of lags in the

climatic system, the climate might also be committed to additional warming.

The magnitude and rate of climatic warming are subject to real uncertainty, especially at the regional level. Projections are detailed in Section 3. A continued build-up of greenhouse gases will, however, clearly increase the strength of the heat-trapping mechanism. The majority of climatologists believe that greenhouse warming will be the dominant cause of climatic change in the next century.

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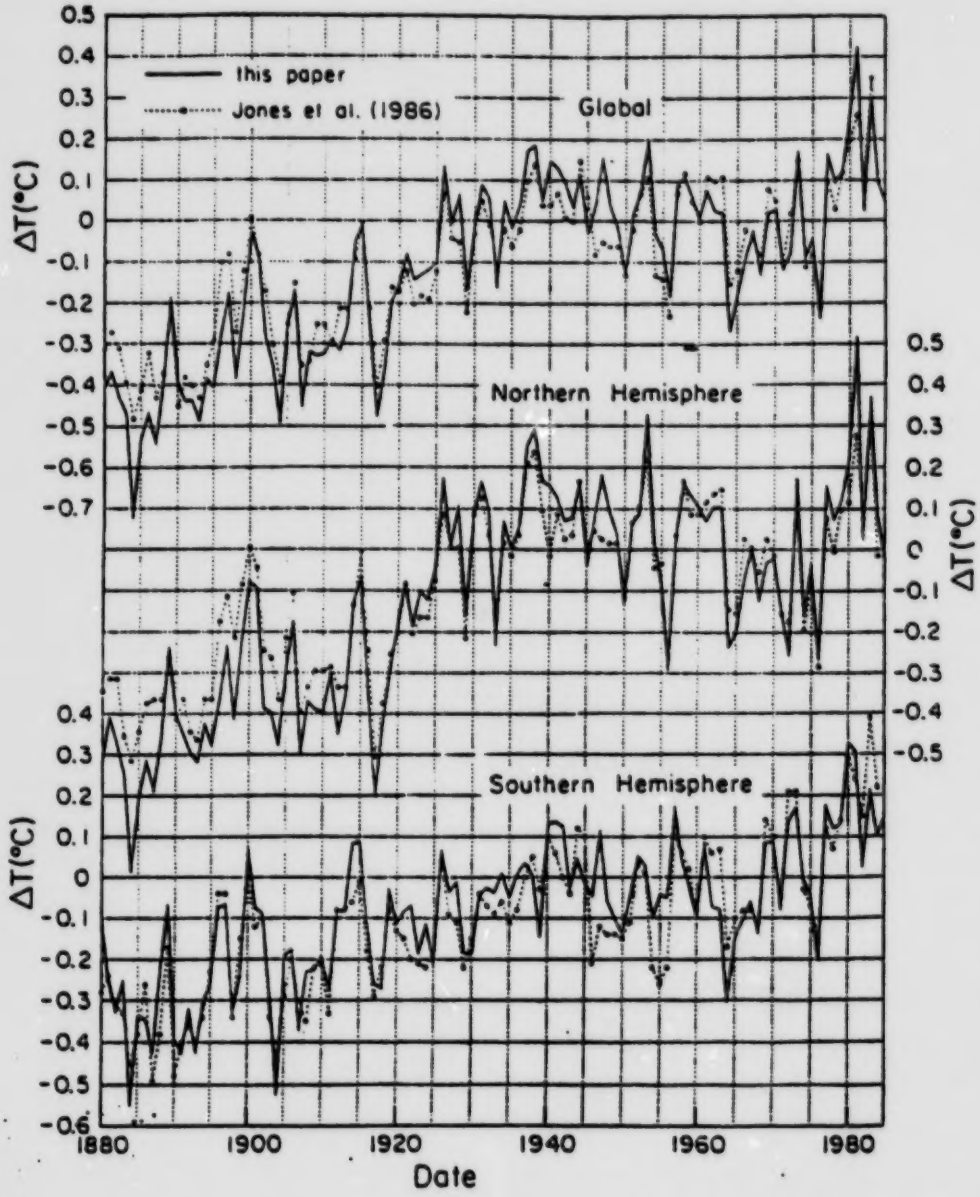

FIGURE 2-1. Global and hemispheric air temperature changes (Hansen and Lebedeff, 1987)

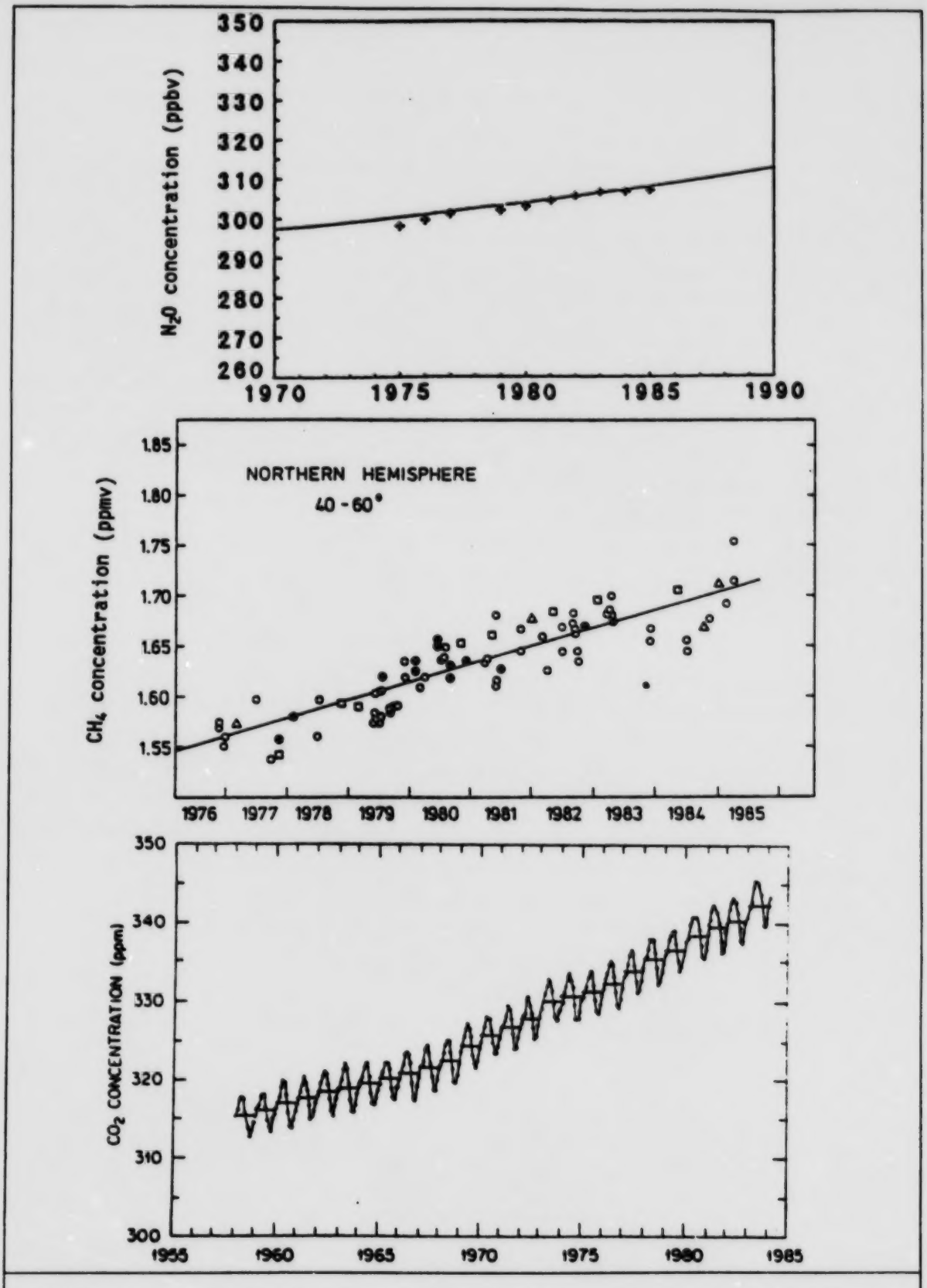

FIGURE 2-2. Trends in measured atmospheric concentrations of CO_2, CH_4 and N_2O (See main text for sources)

3.0 CLIMATIC CHANGE AND IMPACT ON UTILITY SYSTEM OPERATIONS

3.1 Predicting Climatic Change

The main approaches used to project climatic changes due to greenhouse warming geological analogues, historical analogues, and computer models.

The Geological Analogue Approach, discussed in Appendix A3-1, uses warm periods in the past as analogues to study future warming. This provides an independent picture of possible climate changes, but the applicability of past regional climatic change patterns to future warming is questionable. Studies suggest, however, that the increase of tropical temperatures as the global mean temperature rises may be less than indicated by computer models.

The Historical Analogue Approach compares temperature and precipitation patterns during the warmest and coldest years in the instrument-measured climatic record. The approach is most applicable to the initial stages of global warming. Projections for Canada are given in Section 3.3.

Computer models are the main tools used to simulate the climatic response to a CO_2 increase. Most experiments involve one of the following three types of computer models:

- Energy Balance Climate Models: EBCM's resolve latitudinal quantities, and average longitudinal and vertical quantities. They focus on understanding ice and snow feedback mechanisms;

- Radiative-Convective Models: RCM models resolve vertical quantities and average horizontal ones. They focus on understanding radiative heat transfer processes; and

- General Circulation Models: GCM's are 3-D models which explicitly compute atmospheric temperature, winds, pressure patterns, cloud formation, precipitation, and surface hydrological processes.

GCM's used for climatic studies have been developed by the following groups:

- Geophysical Fluid Dynamics Laboratory (GFDL);
- National Centre of Atmospheric Research (NCAR);
- Goddard Institute for Space Studies (GISS);
- Oregan State University (OSU); and
- UK Meteorological Office (UKMO).

The Canadian Atmospheric Environment Service (AES) also has a GCM, and a greenhouse warming experiment was recently undertaken. Detailed results are expected to be available this year (1990).

Most experiments with climate models involve running the model until it simulates an equilibrium (statistically unchanging) climate with the present atmosphere. Atmospheric concentrations of CO_2 are then suddenly doubled, and the model run until a new equilibrium climate is reached.

The Reasons for Confidence in the projected global scale climatic response to increasing greenhouse gas concentrations are that:

- Climate models are based on well-known laws of physics. They have successfully simulated the relative intensities of the greenhouse effect on Venus, Earth, and Mars. These planets have vastly different atmospheric compositions and temperature;

- Tests of algorithms for processes such as infrared and solar radiative transfer agree in several critical areas with field and experimental results;

- Climate models simulate with reasonable success a number of past climates, and many features of the present climate, including important facets of interannual variability; and

- Large scale aspects of the predicted climatic response to a greenhouse gas increase are consistent with scientific expectation. Examples include:

  - Amplification of equilibrium warming at high latitudes;
  - A poleward shift of the mid-latitude precipitation maximum;
  - An overall intensification of the hydrologic cycle; and
  - A tendency for summer evaporation from soils to increase.

Important Limitations to present climate models are that:

- Models are empirically adjusted to fit the observed climate. Examples include changing cloud reflectivity to obtain the overall planetary reflectivity observed from space, and adjusting precipitation fluxes to obtain the observed oceanic salinity;

- GCM resolutions are typically 4 to 7 degrees in latitude and longitude. Mesoscale phenomenon such as the moderating effect of the Great Lakes are currently omitted;

- No model is able to completely simulate the present climate, particularly patterns of precipitation (Cohen, 1986) and soil moisture distribution (Kellogg and Zhao, 1988). Many processes are either not modelled or are represented in highly simplified ways, including:

  - Cloud-radiation interactions;
  - Cloud convective processes;
  - Surface hydrology;
  - Oceanic circulation;
  - Sea ice dynamics; and
  - Interactions with the biosphere.

- Almost all studies have been of the equilibrium response to a sudden increase of greenhouse gases. The real climatic response may not scale linearly with a gradual buildup of greenhouse gases.

GCM's are quite sophisticated tools, usually derived from numerical weather prediction models. Climate modelling is still an infant science, however, and there is a pressing need for more research, especially relating to regional projections. Present climate models cannot adequately resolve mesoscale effects such as the moderating influence of the Great Lakes on climate, for example, or the distribution of precipitation and snowmelt in the Rockies.

Present GCM's require supercomputers. Substantial advances in the models will need the next generation of computers in order to achieve better resolution and to incorporate better representations of oceanic, cloud and other processes (Henry Hengeveld, AES advisor on CO_2 related matters, pers. comm., Jan 1990). Better datasets against which to test the models are also needed. Key data is now being gathered by the 3 satellites that constitute the Earth Radiation Budget Experiment.

3.2 General Predictions

The equilibrium mean annual globally averaged surface air temperature change in response to an effective doubling of the concentration of atmospheric CO_2 is denoted by ΔT_{2x}. The value of ΔT_{2x} projected by various GCM's ranges from 1.5°C to 4.5°C (more recently 2°C to 4°C). This corresponds to mean global rates of temperature change of 0.06°C to 0.8°C per decade. Global mean temperature increases of 0.3°C to 0.5°C above the mean of the 1980's are projected for 2005.

Climatic models tend to agree on mean global, east-west averaged and seasonal patterns of equilibrium climatic change. For example, the value of ΔT_{2x} is projected by the NCAR model to be 3.5°C, by the GFDL model to be 4.0°C, and by the GISS model to be 4.2°C. The AES model projection (preliminary result only) is of a 3.5°C change. Model limitations and analyses of reasons for differences between models are discussed further by Mitchell and Warrilow (1987), Mitchell et al. (1987), Rind (1988), and Meehl and Washington (1988).

GCM simulations of the climatic response to a doubling of atmospheric CO_2 concentrations also predict an overall warming of the earth's surface and lower atmosphere, greatest at high latitudes in the annual mean, and greater in winter than in summer at high latitudes. A general cooling of the stratosphere is expected. An increase of global mean precipitation is also projected, with:

- Mean annual increases at high latitudes;
- Mean annual decreases in middle latitudes;
- Changes of either sign at low latitudes; and
- Precipitation increases in winter and decreases in summer in middle latitudes.

These are robust model projections which are regarded as highly likely. There is little doubt that the hydrological cycle will intensify and evaporation rates will increase. Whether greater evaporation from land surfaces will lead to increased periods of drought depends on regional changes in precipitation.

Global impacts of a climatic warming, discussed in Appendix A3-3, will depend as much on the rate of climatic change as on the change itself. Studies have not examined larger increases than an effective doubling of 1980 atmospheric CO_2 concentrations (350 ppmv to 700 ppmv).

Harvey (1989a) uses a coupled climate-carbon cycle model to assess the climatic response to various scenarios of future fossil fuel use. The scenario projections, described in Appendix A3-2, indicate that an effective doubling of 1988 atmospheric CO_2 concentrations will occur between 2025 and 2050, depending on the scenario assumptions. Other results are that:

- The global mean temperature could be 2.5°C or more above that of the 1980's by 2050. A 1 to 3 decade lag between the build-up of greenhouse gases and the equilibrium temperature response is assumed, and a 2% annual growth of global CO_2 emissions is applied. CFC production is assumed to be phased out;

- The benefit of successive 1% decreases in the growth rate of fossil fuel CO_2 emissions diminishes;

- Stabilizing global fossil fuel emissions at the current level, phasing out CFC's, stabilizing CH_4 and N_2O, and reducing surface O_3 (through reducing NO_x emissions) does much to slow down climatic change; and

- Rates of globally averaged climatic change could reach 0.3°C to 0.4°C per decade by the middle of the next century, implying rates of change of 0.6°C to 1.2°C per decade in middle to high latitudes.

Further discussion of the transient climatic response to an increase of greenhouse gases is given in Harvey (1989b).

3.3 Climatic Change in Canada

Canada's macrogeography and six climatic regions are shown in Figure 3-1, after Hare and Thomas (1979). Most Canadians live in the mid-latitude belt of land adjacent to the United States. Climatic data and a discussion of the present Canadian climate are provided in Appendix A3-4.

Model projections of regional climatic patterns are much less reliable than projections of mean global, east-west averaged or seasonal trends. For almost any given region of the world, some models predict conditions which will be neutral or beneficial to agriculture and water resources, while others predict disastrous conditions.

Figures 3-2a and 3-2b show the global distribution of equilibrium winter and summer temperature changes, respectively, for CO_2 doubling as predicted by the GFDL, NCAR and GISS GCM's (Schlesinger and Mitchell, 1987). The general trends are in clear agreement, but regional details differ substantially.

A robust result of these simulations is that higher latitude countries such as Canada will likely experience climatic changes which are greater by a factor of 2 to 3 times than the global mean changes. The GFDL model predicts a winter warming in excess of 10°C for some parts of Canada, however, while the NCAR model predicts warming of less than 2°C for the same regions. GCM models of present and projected soil moisture distributions for North America, given in Appendix A3-5, also differ greatly.

Predictions of the historical analogue approach are likely applicable only to the initial stages of global warming. Extrapolations to a warming caused by an effective doubling of CO_2 levels should be made with caution since regional responses are likely to be non-linear. Brown and Walsh (1986) undertook an historical analogue study for the Canadian situation (see figures in Appendix A3-5), concluding that:

- Warming will be consistently greatest in the Arctic, accompanied by increased storminess and greater precipitation in most seasons;

- Winter temperatures will increase over most of Canada and the northern USA. This is associated with increased precipitation, except in the northwest United States, southern British Columbia and the Maritimes;

- There will be a general warming in summer; and

- The continental interior will be drier and less stormy in all seasons except winter. Temperature variability will decrease. The variability of summer precipitation, which is convective in nature, will increase.

The Canadian Climate Centre (CCC) has sponsored a series of greenhouse warming studies since 1984. The CO_2 doubling scenario is applied throughout the studies, using output from GFDL and GISS GCM simulations in conjunction with socio-economic, hydrologic and other models.

Ontario

Sanderson (1988) investigated climatic change impacts in the Great Lakes Basin using the GISS GCM. The study took consumptive water demand and economic and demographic changes into account, using Ontario Hydro's 1984 forecasting model, and concluded that:

- Precipitation will decrease by 6% in the SE part of the basin, but will increase by 18% in the NW, with greater overall variability;

- Warmer temperatures will lower winter energy demand and slightly increase summer demand, with an overall decline of 2% to 3%;

- Power generation at Canadian hydroelectric stations, notably the Robert Saunders and Sir Adam Beck units, will decrease by some 4 TWh;

- Mean Great Lakes levels may be reduced by 30cm to 80cm, reducing connecting channel flows by up to 20%; and

- An 11 month ice-free season will result, with maximum ice coverage percentages decreasing to zero on all lakes except for Erie.

Cohen (1986) also investigated the impact of CO_2 doubling on the Great Lakes Net Basin Supply[1] (NBS). Consumptive water demand and the Thornthwaite water balance and mass transfer method provided hydrological input to GISS and GFDL scenarios based on normal and on reduced winds. Results varied from a decrease in NBS of 28.9% for GISS normal winds, to a decrease of 11.7% for GISS reduced winds.

Bhartendu and Cohen (1988) used population-weighted Heating Degree Days[2] (HDD's) to study space heating energy requirements in Ontario following a CO_2 doubling. In the absence of new energy efficient technologies and lifestyles, they conclude that there will be an increased energy consumption up to 2025, since climatic change is not expected to significantly influence energy consumers before about this time. However, for low (1.9% per decade) or moderate (3.6% per decade) population growth, they find that consumption per household will be less in 2065 than the 1985 base by:

- Natural gas: 19% to 28% decrease
- Electricity: 49% to 71% decrease
- Energy: 31% to 45% decrease

Bhartendu and Cohen (1988) calculate that space cooling energy will increase by 6% to 7%, but this is only 10% of the above heating consumption decrease. Melo (1988) notes that further development of the Niagara hydroelectric energy potential is being considered, and that the economic viability of the proposed station could be undermined by long term climatic change.

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[1] NBS is roughly the difference between runoff plus precipitation over lakes on the one hand, and consumption plus evaporation from lakes on the other.

[2] The difference between 18°C and the exterior air temperature.

Manitoba, Saskatchewan and Alberta

Utilities in Manitoba, Saskatchewan and (to a lesser degree) Alberta must cope with greater variability of the present climate than other regions of Canada. Hydroelectric units are largely dependent on drainage basins in the Rocky Mountains. Evaporation rates are locally very high.

A 1988 workshop co-sponsored in 1988 by the Climate Advisory Committees of Alberta, Saskatchewan and Manitoba and by the CCC focused on the impact of global warming on prairie agriculture. The lack of study on water resources was noted (Lawford, 1988). Agriculture, thermal power plant cooling needs and hydro-electric power production are all dependent upon the availability of water. With warming, temperatures are expected to become less variable, but precipitation will be more variable (Rind, 1989). Thus an overall drying will be accompanied by periods of flooding (Brown and Walsh, 1986).

A pilot study of the Saskatchewan-Nelson Basin concluded that there will be a decrease in soil moisture, but failed to determine a consensus on changes in run-off or NBS (Cohen et al., 1989). The study identifies several areas in which research initiatives are needed, including the problem of mapping the spatial distribution of precipitation in complex terrain, and of snowmelt modelling; snowmelt from the Rockies provides much of the surface inflow to the prairie provinces.

British Columbia and Atlantic Canada:

The CCC (Pacific Branch) is initiating a program of climatic warming studies for British Columbia. Little investigation of climatic change in either British Columbia or Atlantic Canada has been undertaken to date (G. McBean, UBC, Pers. Comm., Sept 1989). The thermal inertia of oceans generally exerts a moderating effect on climate, however, and these regions are not expected to experience the more drastic climatic changes projected for Continental Canada. Impacts due to possible sea level changes lie beyond the scope of this study.

Québec

Singh (1988) conducted a preliminary study of the impact of climatic change due to CO_2 doubling on Québec. Scenarios were constructed using the GFDL and GISS models. The study concludes that there could be:

- An increase in NBS of the order of 7% to 20% for the James Bay drainage basins of La Grande, Caniapiscau and Opinaca;
- A potentially large increase in hydro-electric generating capacity of these basins; and
- A decrease in HDD's for Montreal (25%) and Quebec City (35%), which will greatly diminish winter heating requirements across Québec.

A more detailed study, to be released in early 1990, uses the GISS, GFDL and OSU GCM's to model a CO_2 doubling scenario (Méteo-Globe, 1989). The study addresses the potential impact of climatic warming on hydro-electricity production. Thirteen drainage basins north of 49°N were considered, and the draft study results suggest that:

- Precipitation will decrease in summer and increase in winter;
- Heating demand in densely populated areas will decrease by a minimum of 20%, and there will be an overall increase in annual electricity demand of 4.7%; and
- Annual NBS will decrease by 5% (prediction by two models) or increase by 6% (prediction by one model). The problematic balance is between higher evaporation rates and increased precipitation.

North West Territories, the Yukon and Prince Edward Island

Several strong positive feedback mechanisms are expected to amplify any warming trend at high latitudes. Climate studies have not addressed specific regions with any degree of consensus, however. An intensification of the hydrological cycle is anticipated, combined with warmings that may exceed 10°C in places. Much of the Canadian North is classified as a cold desert (less than 10 cm of precipitation per annum), and potential impacts are thus extensive. For example, permafrost zones will only persist if annual mean temperatures remain below about -2°C.

Utility operations in the Yukon, NWT and PEI are small compared to other regions of Canada. Hydroelectric units generate roughly a third of the power needed in the Yukon and NWT. The balance is provided through diesel oil fuel. In the case of PEI, virtually all power generation is through diesel fuel.

3.4 Climate and Utility System Operations

Hydraulic Generating Capacity

The strong relationship in historical data between stream flow, which equates to NBS, and hydraulic generating capacity is shown in Figure 3-3 (Linder et al., 1987). Since present computer climate models cannot directly resolve mesoscale features such as the Great Lakes, the favoured approach to studying the impact of climatic warming on NBS is to input predicted precipitation and temperature changes to hydrological models (Lewis, 1989). For example, the Thornthwaite model estimates runoff and is used for water balance calculations by the Canadian Climate Centre, while the Priestley-Taylor method is often used to evaluate evaporation.

Heating, Cooling and Peak Demand

Base electricity demand is determined by the size and economic activity of the consuming population. Seasonal demand is driven largely by climatic factors (Melo, 1988; Linder et al., 1987), however, mainly due to the use of air conditioning or heating equipment. This strong relationship between ambient temperature and electricity demand is shown in the results of a study

for Southern Ontario, shown in Figure 3-4, which found a correlation coefficient of 0.92 (Sanderson, 1988).

Climatic changes will impact on peak demand (capacity requirements) in addition to energy consumption (generation requirements) (Linder et al., 1987). Bhartendu and Cohen (1987) note that space-heating requirements make up 29% of total electricity demand in Canada. An analysis by Melo (1988) concludes that the electricity demand in Ontario could change by about 3 billion kWh if winter temperatures vary by 5°C over a six month heating season. Similar results will likely apply to other urban centres across Canada. In Western Canada, however, heating is dominated by natural gas rather than electricity.

The energy required to maintain the interior of a building at 21°C is roughly proportional to the HDD's (Hare and Thomas, 1979). This correlation of space heating demand to HDD's allows HDD to be used in place of temperature in modelling electricity demand. Population-weighted HDD's have been used by several workers, for example Bhartendu and Cohen (1988), to examine future demand trends under climatic warming scenarios.

Power Transmission and Distribution

Canadian utilities operate roughly 150,000 km of steel-reinforced aluminum transmission lines, shown in Figure 3-5, with a cumulative design capacity of some 10 GW (EMR, 1989). Present line losses are on the order of 5% to 10%, and the percentage changes in resistivity per °C for steel and aluminum are 0.30 and 0.39 respectively. Losses from power transmission lines and distribution systems will increase under climate warming due to this dependence of impedance on temperature.

Electrical insulation life is also strongly dependent on temperature, and would be adversely impacted by a climatic warming. Aging of insulation is a chemical process which occurs more rapidly at higher temperatures (Fink and Beaty, 1987).

Design loads of support structures such as pylons are factored to withstand freezing rain and snow loads. The frequency of such weather conditions will increase if climatic warming shifts the ambient temperatures of a given area towards zero (Melo, 1988).

In Canada, designing pylon-like structures and guy cables to resist ice accretion is a serious problem. Utilities usually apply their own internal design codes, often modelled on the "Guidelines for Transmission Line Structural Loading" published by the American Society for Civil Engineers (ASCE). National Design codes in Canada are region-specific. For example, design snow loads are given in the National Building Code, while CAN/C.S.A. S37-M86, "Antennas, Towers, and Antenna-Supporting Structures" specifies design ice loads.

Efficiency of Thermal Generating Units

The effective capacity and operating efficiency of gas turbines depend on ambient air temperature. Similarly, the efficiency of steam generators is sensitive to air temperature changes, and also to the temperature of water used for cooling during the condensing stage of the steam cycle (Linder et al., 1987). Power plants using once-through cooling could be adversely affected by decreases in stream flows. This will reinforce trends in North America toward cooling by evaporation and the siting of generating units near a coast, where possible (Smith and Tirpak, 1988).

3.5 Planning

Canadian electric utilities operate power generation and distribution networks in a climate characterized by seasonal extremes of temperature and precipitation. A changing climate is unlikely to produce weather conditions beyond the present operating experience of Canadian utilities, and climatic data is routinely considered in the design of utility operations and systems. Such data has traditionally been considered unchanging in nature but, if

projections of climatic change are correct, this will no longer be the case.

The U.S. EPA's (draft) report to Congress on Potential Climate Change Impact recommends that utility decision makers begin to consider climatic change as a factor in planning new capacity (Smith and Tirpak, 1988). The report notes that, over a 20 to 30 year period, impacts of climatic change are similar to other risks and uncertainties that need to be considered. Utility planning horizons of 30 years are not uncommon (Linder et al., 1887).

Planning decisions take into account projected electricity demand, return periods of drought, and other calculations which will increasingly have to consider projections of future climatic changes rather than past climate analysis. For example, Mobil are reported to now take projected sea level changes into account in oil rig design calculations. Some projections call for significant climatic changes within the design lifetime of structures to be built over the next few years.

Utility planning factors identified by Linder et al. (1987) are:

- Electricity sales;
- Annual and seasonal peak demand;
- Generating capacity requirements;
- Fuel utilization by type of fuel; and
- Capital and operating costs.

Their approach to evaluating the potential impact of climatic change on these factors is shown in Figure 3-6. Five tasks necessary to the evaluation, shown in Figure 3-7, are:

- Develop base case utility planning scenarios;
- Develop weather-sensitivity of demand;
- Develop weather-sensitivity of supply;
- Develop alternative planning scenario outputs; and
- Compare base case and alternative case scenario outputs.

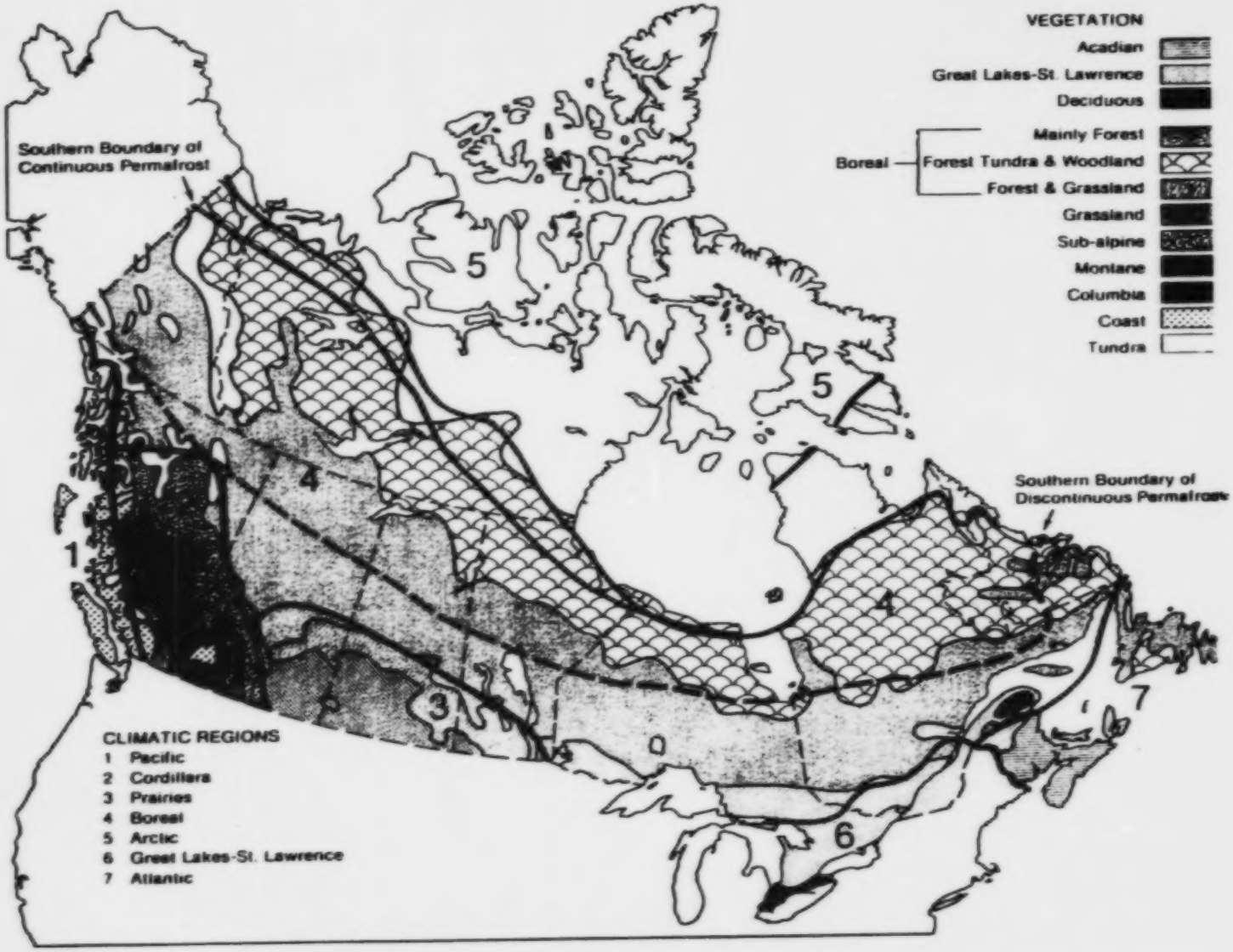


FIGURE 3-1. Canadian macrogeography and climatic regions (Hare and Thomas, 1979)

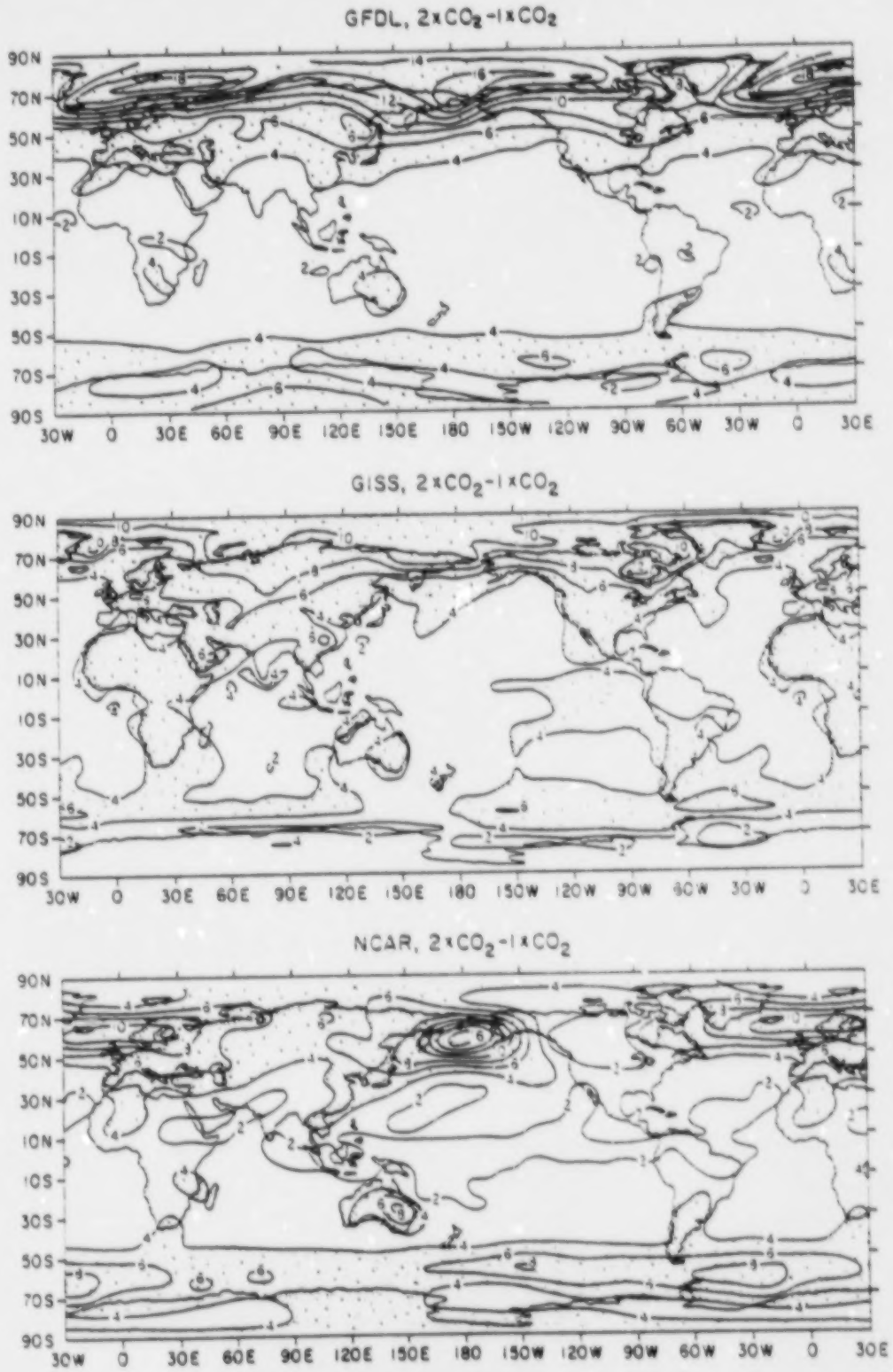


FIGURE 3-2A. GCM predictions of equilibrium winter temperature changes (Deg C) for CO_2 doubling (Schlesinger and Mitchell, 1987)

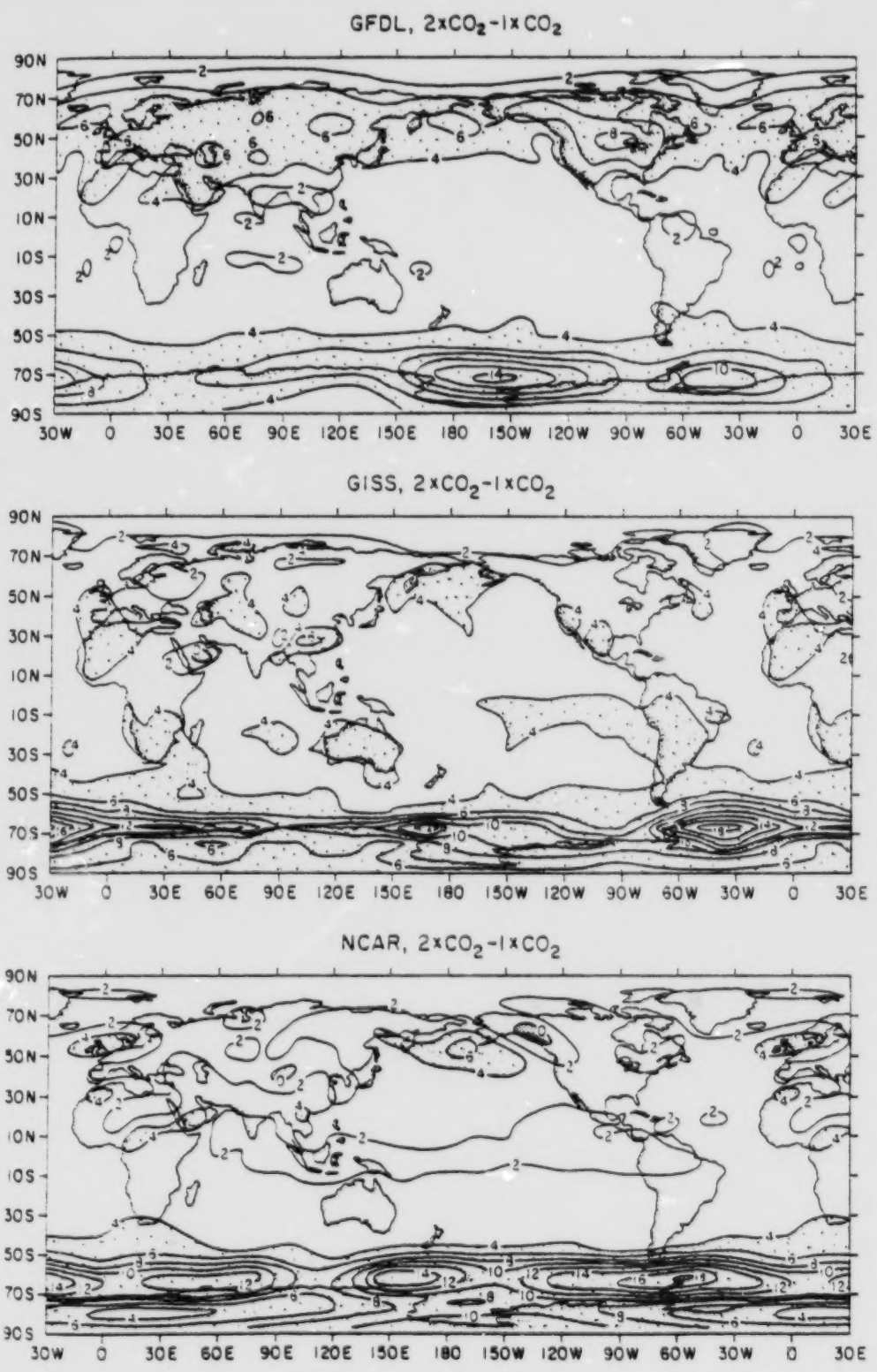
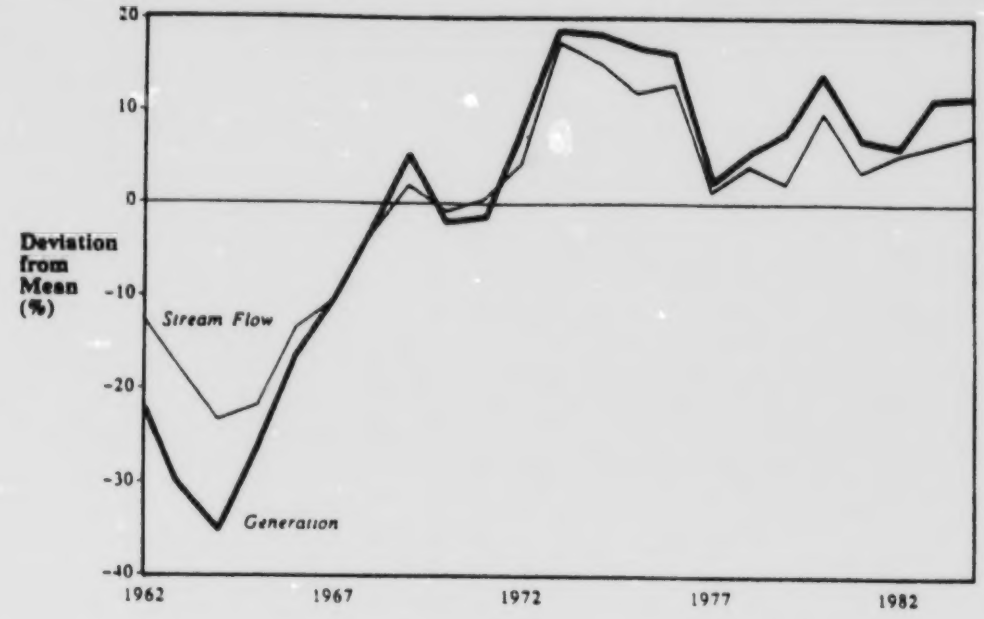
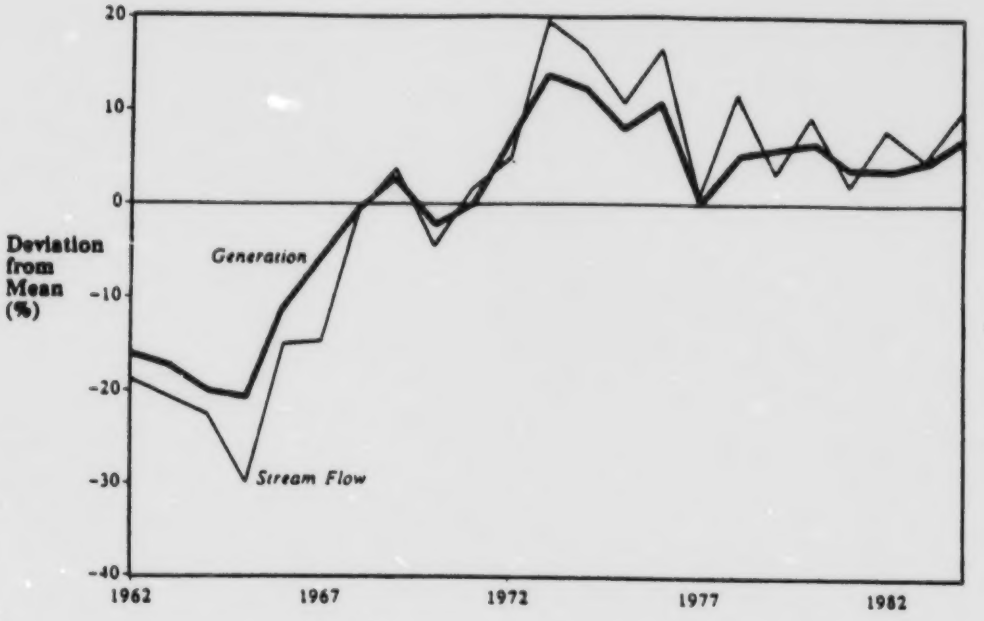


FIGURE 3-2B. GCM predictions of equilibrium summer temperature changes (Deg C) for CO_2 doubling (Schlesinger and Mitchell, 1987)



STREAM FLOW AND ELECTRICITY GENERATION
NIAGARA HYDRO PROJECT



STREAM FLOW AND ELECTRICITY GENERATION
ST. LAWRENCE HYDRO PROJECT

FIGURE 3-3. Historical relationship between stream flow and hydraulic generating capacity (Linder et al., 1987)

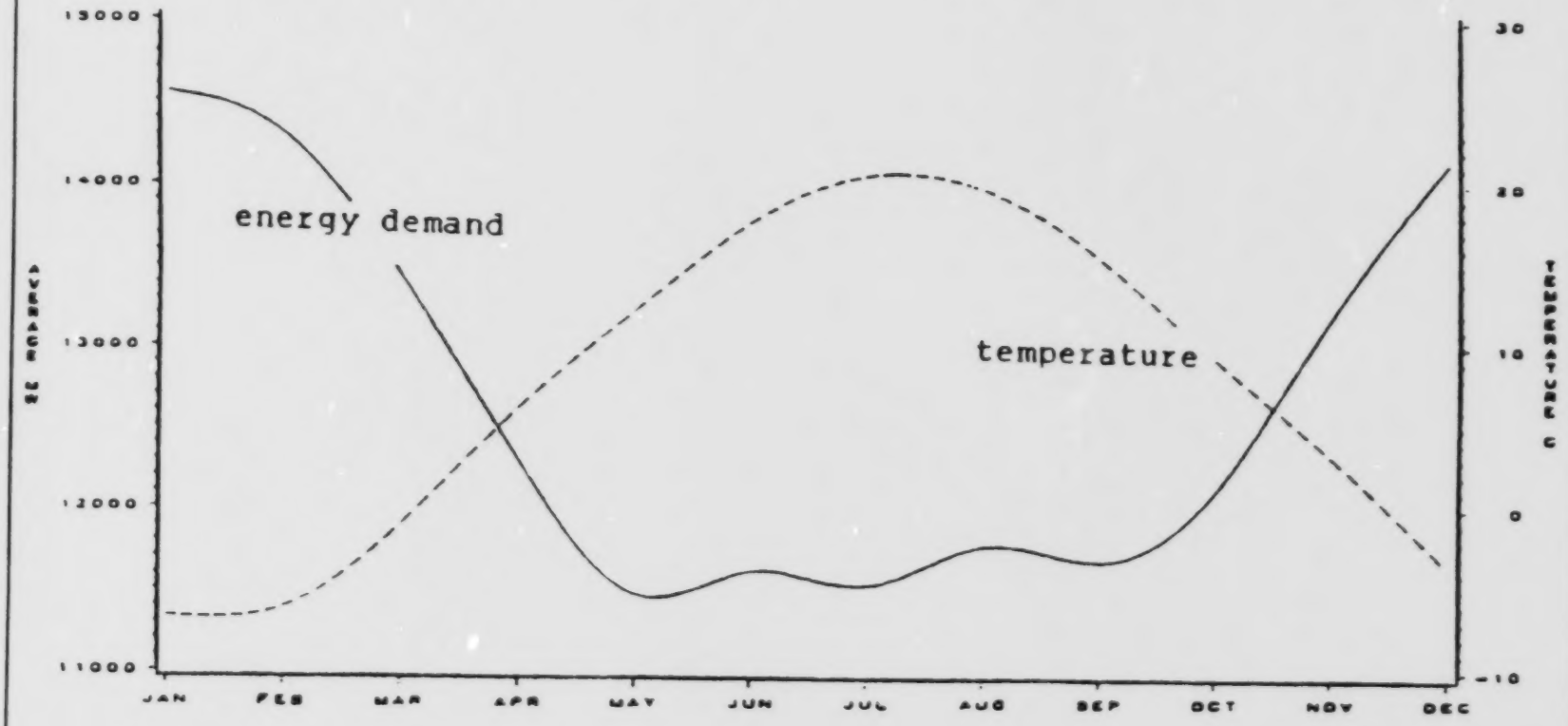


FIGURE 3-4. Historical relationship between temperature and electricity demand in Southern Ontario (Sanderson, 1988)

Provincial and international systems

Long distance systems

FIGURE 3-5. Power transmission systems in Canada (EPIC, 1988)

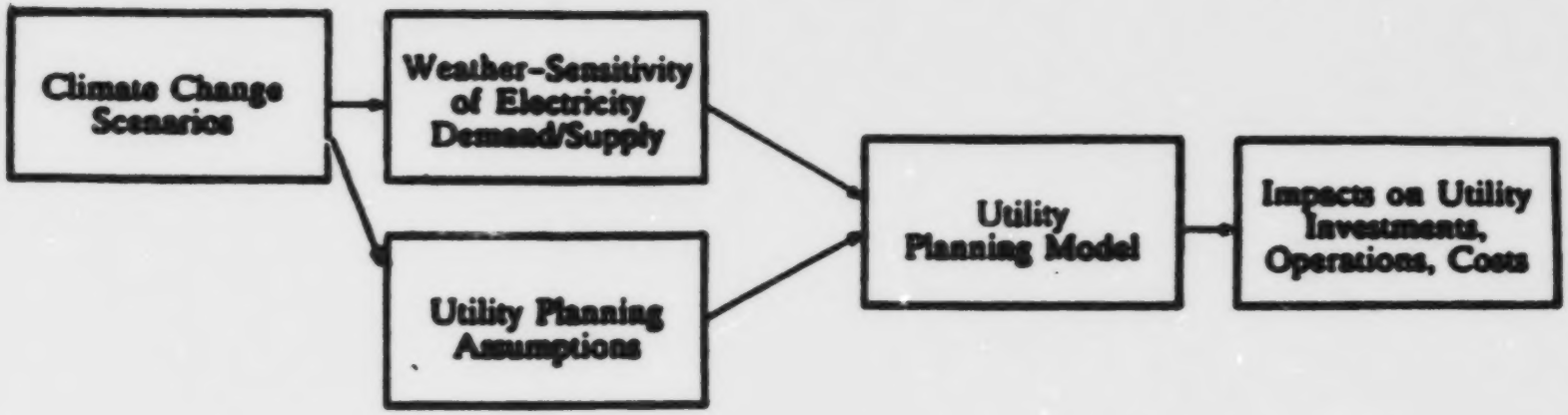


FIGURE 3-6. Utility planning model for climatic change (Linder et al, 1987)

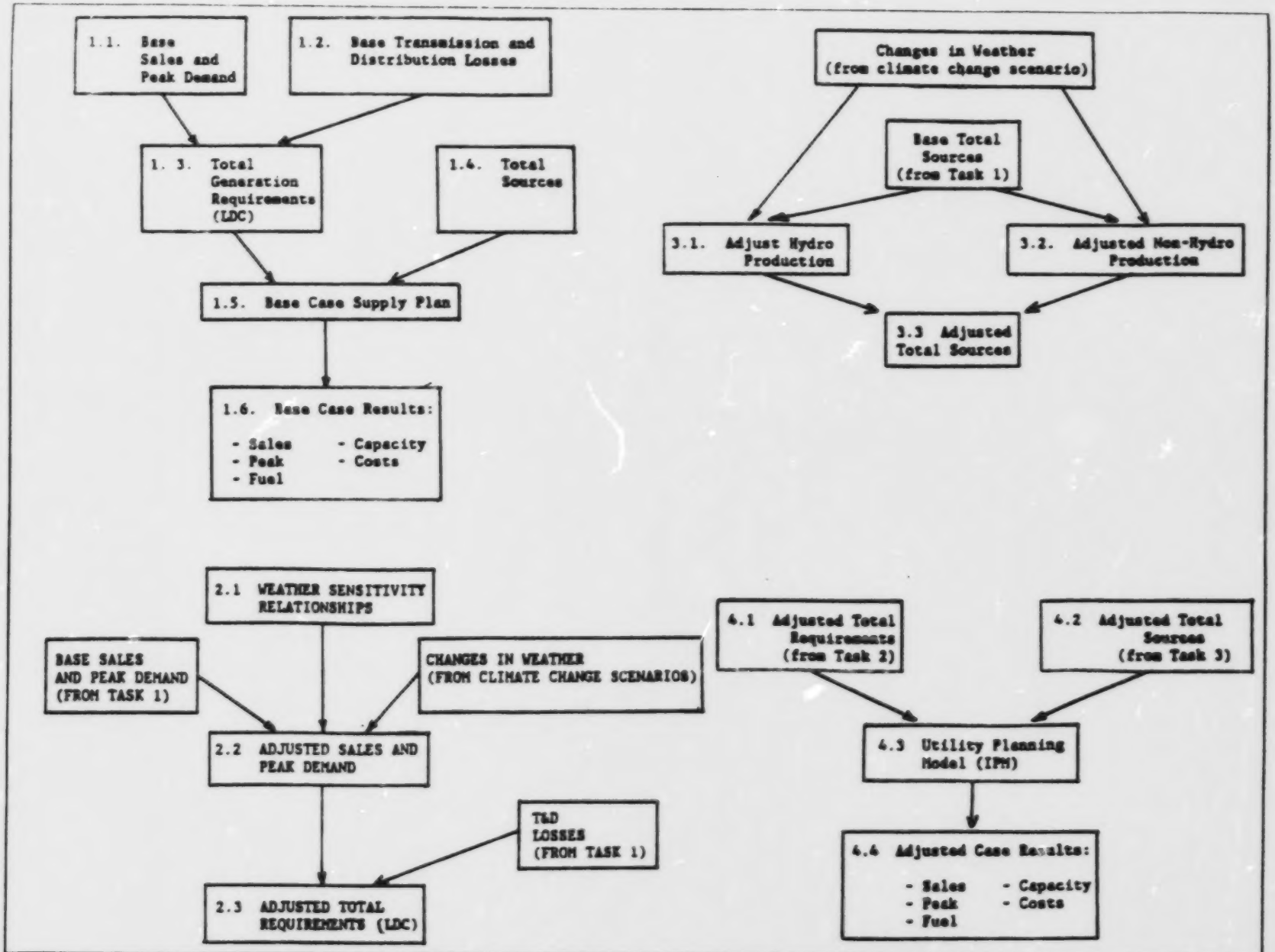

1.1. Base Sales and Peak Demand
1.2. Base Transmission and Distribution Losses
1. 3. Total Generation Requirements (LDC)
1.4. Total Sources
1.5. Base Case Supply Plan
1.6. Base Case Results:
- Sales
- Peak
- Fuel
- Capacity
- Costs
Changes in Weather (from climate change scenario)
Base Total Sources (from Task 1)
3.1. Adjust Hydro Production
3.2. Adjusted Non-Hydro Production
3.3 Adjusted Total Sources
2.1 WEATHER SENSITIVITY RELATIONSHIPS
BASE SALES AND PEAK DEMAND (FROM TASK 1)
CHANGES IN WEATHER (FROM CLIMATE CHANGE SCENARIOS)
2.2 ADJUSTED SALES AND PEAK DEMAND
T&D LOSSES (FROM TASK 1)
2.3 ADJUSTED TOTAL REQUIREMENTS (LDC)
4.1 Adjusted Total Requirements (from Task 2)
4.2 Adjusted Total Sources (from Task 3)
4.3 Utility Planning Model (IPM)
4.4 Adjusted Case Results:
- Sales
- Peak
- Fuel
- Capacity
- Costs

FIGURE 3-7. Development of i) Base case scenario; ii) Weather sensitivity of demand; iii) Weather sensitivity of supply; and Alternative case study scenarios. (Linder et al, 1987)

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4.0 POLICY ASSESSMENT

4.1 World

The Toronto Conference in June 1988 on "The Changing Atmosphere", sponsored by the Canadian government, generated much of the recent activity to develop options to deal with the buildup of greenhouse gases. The conference called for a 20% reduction of global CO_2 emissions from 1988 levels by 2005, and for governments to work urgently towards an international convention as a framework for protocols on the protection of the atmosphere. Several other strong international declarations on the greenhouse effect and other environmental issues were made in 1989 (see Appendix A4-1), including:

- The Hague Declaration (March 1989), to which Canada is a signatory. This states that "Today, the very conditions of life on our planet are threatened by severe attacks to which the earth's atmosphere is subjected", and calls for action to limit future climatic warming

- The G-7 Summit Final Communiqué (July 1989), to which Canada is also a signatory. This states that " We strongly advocate common efforts to limit emissions of CO_2 and other greenhouse gases"

- The New Dehli Meeting of scientists from developing countries, February 21-23. The consensus statement describes the greenhouse problem as "The greatest challenge ever faced collectively by mankind"; and

- The Belgrade Meeting of non-aligned nations issued an 11-point statement on environmental issues, stating that "changing global climatic patterns threaten present and future generations with severe economic and social consequences and that necessary and timely action should be taken".

The Canadian government convened a meeting of legal experts in Ottawa in February, 1989, to discuss principles and issues relevant to a convention[3] on climatic change. The governments of Canada, Malta and the Netherlands are working to develop a framework for a convention. The Dutch government hosted an ad hoc meeting of invited environment ministers in The Hague in November 1989, at which the draft convention scope was presented. It is expected that the United Nations Environment Program (UNEP) will be asked to hold a conference in order to negotiate the wording of a convention.

The Intergovernmental Panel on Climatic Change (IPCC) was established by the World Meteorological Organization (WMO) and UNEP. The IPCC is the most important international body examining the greenhouse problem, and will strongly influence subsequent policy development. The three IPCC working groups are:

Group	Focus	Chairing Country	Canadian Members
1	Scenarios	UK	G. McBain (UBC)
2	Impacts	USSR	T. Brydges, K. Dawson (AES)
3	Policy Responses	USA	J. Beesley, R. Rochon Dept. of External Affairs R. Pantland Inland Waters Directorate

As part of the work of the IPCC, 163 representatives from 43 governments held a workshop in Geneva (Oct 2-6, 1989), to discuss means of implementing response options. Most nations advocated parallel development of a convention and protocol, and some proposed a (somewhat optimistic) timetable aimed at concluding a convention by 1991 and establishing a protocol in 1992.

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[3] A convention aims at producing a general agreement between nations on how to approach some goal; for all practical purposes it is non-binding. A protocol specifies commitments and action timetables to achieve the objectives outlined in the convention upon which it is based. An example is the 1985 Vienna Convention on Ozone-depleting substances and its 1987 Montréal Protocol.

The Second World Climate Conference will focus on policy responses to the greenhouse problem. It is being coordinated by Howard Ferguson, former director of the AES and of the 1988 Toronto Conference, and will be held in Geneva in November 1990. Final IPCC working group reports will be presented to the conference and to the UN General Assembly in November 1990.

4.2 North America and Europe

Canada

The focus of government activity at the national level is the Task Force on Energy and the Environment, established by the Federal-Provincial-Territorial Energy Ministers in August 1988. A preliminary report by the Task Force, summarized in Appendix A4-2, concluded that the Toronto Conference call for a 20% reduction of 1988 CO_2 emission levels by 2005 should be regarded as an illustrative target only, pending further study of the issues. The general agreement by Canadian Energy Ministers on approaches to the greenhouse issue is in itself significant. No such consensus emerged during the energy shortages and spiralling world oil prices of the 1970's.

The United States

The U.S. Environmental Protection Agency (EPA) recently released a report entitled "Policy Options for Stabilizing Global Climate" (EPA, 1989), whose recommendations will be used by the U.S. delegation to the IPCC. The report identifies both short and long-term policy options (Appendix A4-3).

The EPA is developing a strategy for international cooperation in dealing with the greenhouse effect. The National Energy Conservation (Appliances) Act of 1987, although not motivated by the greenhouse effect, will contribute to reducing electric utility emissions. This act sets down minimum efficiency standards for appliances which could require design changes in 70-90% of the

appliances on the market in 1987.

Two bills were presented to the U.S. Congress in 1989 aimed at reducing CO_2 emissions by 20% by 2000. The "Global Warming Prevention Act", gives highest priority to promoting U.S. energy efficiency and renewable energy R & D programs (Physics Today, Oct 1989, pp52-54). The "International Tropical Forestry and Energy Efficiency Act" will fund programs to develop alternatives to deforestation and to improve energy efficiency in developing countries (World Climate Change Report, Oct 1989, p 6).

The European Community (EC)

The EC Council of Ministers has stated that the response to global warming, "Should be made without further delay irrespective of remaining uncertainties on some scientific aspects of the greenhouse effect". The Council also "Invites the Commission and Member States to take urgent action to increase energy savings; to improve energy efficiency" (Energy Committee, 1989), and is working on plans to deal with the greenhouse effect which would be initiated at the national level by the 12 EC member countries.

In its Fourth Environmental Action Plan (1987) the EC called for an energy efficiency improvement of at least 20% by 1995 and a market share of renewables of 5% by 2000 (Owens and Hope, 1989).

The United Kingdom

The energy committee of the British House of Commons published in July 1989 a report entitled "Energy Policy Implications of the Greenhouse Effect" (Energy Committee, 1989). The conclusions, presented in Appendix A4-3, propose that Britain be prepared to act unilaterally to reduce CO_2 emissions.

Recent British government legislation requires that up to 20% of future electricity should be from non-fossil fuel sources (Energy Policy, April

1989, pg. 143). The British Government recently cancelled the UK nuclear program. The Energy Committee notes that with best practice, Britain might be able to cut its CO_2 emissions by 50% by 2020, but that China will by then have increased its emissions by 20 times Britain's savings. They suggest that the developed world might more cost-effectively invest in Third World CO_2 reductions.

At the recent World Energy Conference in Montréal, John Wakeham, UK Secretary of State for Energy, suggested that CO_2 emissions could be limited through a system which allows energy users to compete for a limited number of permits to emit CO_2 and to trade these permits on the secondary market. He also stated that, "we shall need to act before we have proved and analyzed all the aspects". (World Climate Change Report, October 1989, p17)

Sweden

Sweden supports several electricity-intensive industries, and about 50% of electricity presently being generated by nuclear energy. Sweden is committed to phasing nuclear power out by 2010, however, and further hydroelectric development is severely restricted by legislated protection of the environment.

Vattenfall, the Swedish State Power utility, convened a workshop in May-June 1989 to address its electricity problems (Johansson et al., 1989). The workshop assessed measures to increase the efficiency of electricity generation from fossil fuels, increasing electricity end-use efficiency in all sectors, and evaluated alternatives in Sweden to nuclear, fossil-fuel, and hydroelectric power. Supply and demand scenarios are presented in Appendix A4-4 which indicate that it is technically possible, using available technology, for Sweden to reduce its CO_2 emissions from electricity generation by 20% while both phasing out nuclear power and maintaining economic growth.

Unlike Canadian utilities, Vattenfall can increase electricity prices without

prior government approval, and it is expected that plans for a significant price increase will be announced soon (Abrahamson, Pers. Comm. Oct 2 1989). Extra revenue will be used to help customers switch to more energy efficient end-use equipment, so that electricity bills will change little.

Sweden is committed to not increasing CO_2 emissions (Cabinet Proposition 1897/88:85). Although the wording says "carbon dioxide", there are indications that this is being interpreted as "greenhouse gases", and that Sweden will credit itself with phase-out of CFC's, which would allow CO_2 emissions to increase (Abrahamson, Pers. Comm., Oct 25 1989).

Norway

The Norwegian government is very active in international environmental forums. The Norwegians propose that industrialized countries allocate 0.1% of their gross national products to an international atmospheric fund (Brundtland, 1989). The fund would help finance transitional measures in developing countries as well as reforestation.

West Germany

West Germany has established a commission (the Enquete Commission) to examine options to reduce CO_2 emissions. An improvement in energy use efficiency in all sectors of the economy is considered a key ingredient of short term measures, with a gradual move to non-fossil fuel energy supplies in the long term. West Germany is currently the largest government supporter of solar energy research in the world (US $ 65M in 1988).

Wilfrid Bach, member of the Enquete Commission, and Hermann Scheer, member of the German Parliament, propose a uniform 0.5 cent/kWh CO_2 tax on fossil fuel use in all OECD countries. At current rates of fossil fuel use, this tax would raise $200 billion annually. Half of this would be used to reduce Third World debt with no strings attached; the other half would be used for forest

and soil protection, agricultural reforms, improvements in energy use and supply, and family planning coupled with old age security in Third World countries.

The Netherlands

The Dutch government issued a National Environmental Policy Plan (NEPP) in May 1989, calling for stabilization of CO_2 emissions at 1989-90 levels by the year 2000. In an August 28 speech during the election campaign, Prime Minister Ruut Lubbers went further, calling for an 8% emission reduction over the next 4 years. The Dutch government was re-elected in September 1989. A number of environmental groups in the Netherlands are calling for a 10 to 30% reduction of Dutch CO_2 emissions by year 2000.

4.3 Australasia and the Soviet Union

Australia

Australian Prime Minister Hawke issued a statement on the environment in July 1989 entitled "Our Country, Our Future" in which the issue of greenhouse warming is addressed. Mr. Hawke states that "We cannot afford to wait for conclusive scientific evidence of climatic warming... Our short term responses need to be cost-effective, and our longer term responses based on the outcome of research now being set in train". The following policies are mentioned as possible means of reducing greenhouse gas emissions:

- An emphasis on limiting CH_4 emissions, which are reported to comprise a greater proportion of Australia's greenhouse emissions than of global emissions;

- An emphasis on creation of carbon sinks through reforestation. Mr. Hawke has pledged planting one billion trees throughout Australia by the year 2000; and

- Improvements in the efficiency with which energy is used, and efforts to reduce waste of energy, particularly in transportation energy use.

There is no discussion of the means of implementing these measures, their costs, or of their quantitative effect; rather, the Prime Minister states that, "We are likely to find it much more difficult to reduce CO_2 levels than some other countries. We may even need to increase levels to accommodate growth of internationally competitive export industries".

The State Government of Victoria issued a statement entitled "The Greenhouse Challenge: The Victorian Government's Response" in June, 1989. In it the Victorian Government announced the following objectives:

- Significant reduction of greenhouse gas emissions by 2005;

- Adoption of the Toronto conference goal of a 20% reduction of CO_2 emissions by 2005 as an interim planning objective, subject to review in 1991 of parallel commitments made elsewhere; and

- To at least match any international agreements for greater reduction.

Low-grade brown coal provides 85% of Victoria's electricity, accounting for about 50% of the state's emissions. Use of nuclear power is prohibited on safety and environmental grounds. The response to climatic change appears to be the most comprehensive proposal by any state-level government in the world. Actions proposed to meet emission reduction targets, and a position paper by the state's electric utility, are presented in Appendix A4-3.

Japan

Japan has made a concerted drive to improve the energy efficiency of its economy, although Japanese CO_2 emissions are projected to increase from 953 Mt in 1986 to 1,525 Mt by 2030. An analysis of current and projected worldwide CO_2 emissions by the Ministry of International Trade and Industry (MITI) singled out the U.S., USSR and China as the major nations requiring CO_2 emission controls (Nature, 20 July 1989, page 176).

High officials in the Japanese government are quoted as saying that it would be unfair to call for a uniform reduction of CO_2 emissions, since countries such as Japan have already reduced emissions for reasons unrelated to climatic change (World Climate Change Report, Oct 1989, p5). Also, Japan's per capita CO_2 emissions are very low among the major industrial nations.

There is a growing awareness of global environmental problems in Japan and of the Japanese responsibility to contribute to their solution. Japan participates in a project of the UN Economic and Social Commission for Asia and the Pacific (ESCAP) entitled "Prospective Consumption of Fossil Fuels in the Asia-Pacific Region and its Climatic Implications" (Takahashi, 1989). This project will examine policy options, with a draft report to be published in June 1990 and a symposium in Tokyo during the second half of 1990.

An international conference on atmospheric change and sustainable development was hosted by Japan on 11-13 Sept, 1989. The conference will significantly influence Japanese policy goals. It called for investigation of ways to keep atmospheric CO_2 concentration below 560 ppm, which is twice the pre-industrial level, including "urgent steps" to increase energy efficiency and the use of non-fossil fuel energy (World Climate Change Report, Oct 1989, p 10). Japanese Prime Minister Kaifu stated that Japan will take the initiative to develop energy technologies to counter global warming. He re-affirmed the intention of the Japanese government to increase environmental aid to developing countries by 60%, spending US $2.25 billion over the next 3 years.

Japan's position paper to the IPCC working group on response strategies reflects the Japanese government's resistance to restrictions on its own emissions, and its interests in technology development and transfer to developing countries. Japan is downwind of China, and a major expansion of Chinese coal use with current technology may produce an acid rain problem in Japan. China has a serious and growing acid rain problem of its own (Galloway et al., 1987), and Japan could serve the interests of both countries by assisting a move to efficient clean coal technologies.

China and India

China shows no interest in responding to the greenhouse gas buildup in any way that will restrict use of its own fossil fuel resources. The Chinese intend to meet their own coal needs from domestic supplies and to export as much coal as possible (Desai, 1989), and plan to expand coal production from the present annual level of 900 Mt to 1,600 Mt by 2000 (Boyle, 1989). In order to reduce domestic oil consumption and enhance oil exports, China is also attempting to switch from oil to coal wherever possible.

Climate models do not agree on the effect of global warming on the Indian monsoon, but some Indian meteorologists fear adverse effects. At the New Delhi meeting in Sept 1989, former Indian Prime Minister Rajiv Gandhi advocated a "polluter pays" principle to create a global fund to assist Third World countries in rebuilding polluting plants, and for technology transfer (World Climate Change Report, Oct 1989, p 18).

CO_2 emissions from countries such as China are high (China ranks third globally) and projected increases are much higher than those from countries already industrialized. On a per capita basis, however, CO_2 emissions from these countries are much lower than those of industrialized nations (Appendix A6-1).

Pacific Rim Countries

Neither newly industrialized Pacific Rim countries, such as Taiwan and South Korea, nor rapidly industrializing countries such as Malaysia and Thailand appear to be considering the potential impact of climatic warming on their energy supply and demand. Both groups of countries are hoping for economic growth rates of 4-6% per year over the next decade and plan to significantly increase their use of coal. The Korean Electric Power Corp. operates nine nuclear power plants and plans to build three more (CANDU-type) units. Energy policies and related environmental concerns of these countries are presented in Appendix A4-5.

The Soviet Union and Eastern Europe

The Soviet Union has indicated no official position on the greenhouse problem, and is heavily dependent on coal. The USSR is responsible for about a fifth of global CO_2 emissions, and both Poland and East Germany emit large quantities of CO_2.

Pollution in the Soviet Union, and in Eastern Europe as a whole, is a severe and widespread problem. Reversing environmental deterioration is becoming a priority action item, and the Soviet Parliament has tabled draft legislation to tackle the problem systematically. Five major environmental groups have emerged over the past two years, the largest being the Soviet Ecological Union; none yet have an official voice in parliament, but are nevertheless considered influential (The Economist, Nov 4, 1989).

Organizations such as the World Bank are increasingly linking aid to Poland and other Eastern European nations to the concept of Sustainable Development (WCED, 1987; Bruntland, 1989). The goal is to simultaneously address the restructuring of economies and pollution problems.

Based on the results of their geological analogue approach to predicting climatic change, however, Budyko and Sedenov (1988) conclude that a warmer

climate will be beneficial to man, and that "limiting carbon fuel consumption will be not only useless but even dangerous... any efforts to restrict the use of coal would be a crime against humanity". Budyko is an influential and respected Soviet scientist, but it appears that his position is not shared by many Soviet climatologists. Yuri Israel, head of the Soviet meteorological service and the Soviet Chair of the IPCC Impacts Group is most concerned about effects of rapid climatic change, (T. Brydges, Pers Comm. 2 Nov 1989). Budyko may well be right to say that a warmer climate will be beneficial, but CO_2 emission restrictions would still be needed to slow down the rate of climatic change to a manageable level.

4.4 Non-Government Organizations (NGO's)

Common features of most actions advocated by NGO's are:

- Emphasis on improving the efficiency of energy use rather than a supply-side emphasis, recognizing that this will require higher energy prices and measures to reduce market barriers to more efficient technologies;

- Imposition of a carbon tax to encourage energy conservation and to improve the competitiveness of non-CO_2 emitting fuels;

- A need to reassess the potential of biomass; and

- Offsetting reforestation to compensate for emissions in excess of agreed-upon emission targets.

Many NGO's recognize that substantial near-term increases of CO_2 emissions by developing countries are inevitable, and call for larger emission reductions than 20% by 2005 by industrialized countries. The agendas of two prominent U.S. NGO's, the Natural Resources Defense Council and the Environmental Defense Fund, are presented in Appendix A4-6.

In July, 1989 a consortium of Canadian environmental and aboriginal groups issued, "Greenprint for Canada: A Federal Agenda for the Environment" to Prime Minister Mulroney. The groups represented, together with their recommendations, are listed in Appendix A4-6.

4.5 Policies for Other Greenhouse Gases

Reducing the emission rate of CH_4 by only 10% will likely stabilize its concentration at the present level. Policies being considered include:

- Capturing CH_4 from municipal landfill sites and from coal mines;
- Reducing venting and leakage of CH_4 from natural gas systems; and
- Research on CH_4 emission reduction from rice paddies and cattle.

The production of CFC's will probably be largely eliminated by the year 2000 because of the threat they pose to stratospheric O_3. This will result in their concentrations peaking by about the year 2000, then slowly declining. Some jurisdictions already require capture and destruction of CFC's from discarded refrigerators and air conditioners.

Emissions of NO_x are being reduced in some countries because of acid rain and urban air pollution concerns. Reduced NO_x emissions will lead to reduced production of tropospheric O_3, another greenhouse gas. Nitrous oxide (N_2O) is at present only a very minor greenhouse gas, and research is underway to examine the extent to which changes in agricultural practices could reduce its emission from agricultural land.

4.6 Canadian Legislative Action Considerations[4]

The legal foundation for future regulation of CO_2 emissions and illustrative regulatory options are reviewed in Appendix A4-7. Existing regulatory regimes have evolved with little uniformity in scope or content (see, for example, CEA 228 GSOA, 1982), but there are clear trends which will have an impact on CO_2 regulatory policy.

The Federal government has wide constitutional powers to regulate matters of national concern, but in practice the provinces have played a more extensive role in environmental protection. The Federal government can promulgate non-binding environmental quality objectives, guidelines or codes of practice under the Canadian Environmental Protection Act, CEPA, with implementation by the provinces as determined by federal-provincial negotiation; or it can enact regulations to directly control source emission of pollutants, when such emissions affects another country or results in violation of an international agreement to which Canada is a party. The Federal Minister must first give the provinces an opportunity to correct the problem, however, and no regulations have ever been made under these provisions. Federal-provincial co-operation and negotiation will likely continue to be cornerstones of regulatory action in Canada.

Provincial regulations are moving away from standards based on concentration at the point of impingement to standards tied to progressive reductions of emission levels and the best technology available. The Ontario water pollution reduction program (the Municipal-Industrial Strategy for Abatement, MISA), for example, involves monitoring regulations followed after a period of one year by limits regulations. Other programs set target emission levels with industry delegated the responsibility of achieving those levels within a given time frame.

The general public has had little opportunity in the past to participate in

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[4] Authored by the Canadian Institute for Environmental Law and Policy

the regulatory process. Negotiation with industry has served as an important tool to render control orders unnecessary in Alberta, however, and review periods are available for comment on standards in Québec. In Ontario, too, there is a strong trend toward the involvement of non-government groups in the regulatory process. The CEPA further supports the existence of such a trend by providing for boards of review before which any person has standing to appear and make submissions. It is clear that non-government participation in the law-making process is being allowed and encouraged. The role of consultation between the public and private sectors is increasingly becoming a fundamental part of the Canadian framework for regulation.

Scientific consensus and the work of non-government organizations, public interest groups and the academic community can substantially influence regulatory policy and public opinion. Public opinion driving reform may also be influenced by quality of life considerations. The role of international trends and obligations in bringing about regulatory action can be a substantial one, as illustrated by the response to international initiatives on CFC's. Voluntary measures adopted by industry for economic or other reasons could be incorporated into technology-based regulation. Political motivations pervade the regulatory process in the form of manoeuvering for political advantage during elections or by governments adopting strategies during negotiation of international agreements designed to secure a particular advantage or benefit. For example, the reluctance of less developed countries to participate in a global warming treaty unless provision is made for free transfer of technology to them.

Time frames for action on CO_2 emissions can be estimated by examining existing regulatory programs, such as MISA at the provincial level and CFC controls at the federal and provincial levels. The MISA timetable covers about a six year period from the time of initial consultation to the deadline for compliance with a limits regulation. The CFC example is of an even more rapid pace of implementation with the enactment of domestic measures four years after the negotiation of an international agreement and only two years after

agreement was reached on a CFC protocol.

No definitive timetable can be estimated for CO_2 regulatory reforms, but it is clear that the pace will be intensive compared to traditional time frames and that action could be extremely rapid. Provinces are more likely to take action for the constitutional and practical reasons highlighted above and could do so in a quite short period of time as evidenced by the MISA and Countdown Acid Rain examples in Ontario. International proposals are for stabilization of emissions by the year 2000 and a 20% reduction by the year 2005. Although this timetable may not ultimately be adopted, the trend towards comprehensive and more stringent environmental protection measures suggests that when actions are agreed upon, they are likely be stronger than those actions now being proposed, not weaker.

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5.0 CANADIAN ELECTRICAL ENERGY AND THE COAL INDUSTRY

5.1 Energy Resources Overview

5.1.1 The Need for Coal

Scenarios of future world energy demand are presented in Appendix A6-2. The scenarios assume various optimistic global population projections. Non-fossil power generation units are installed at a rapid rate, equivalent to 150 new nuclear plants every year, to meet the growth in energy demand. Vigorous promotion of energy conservation is also assumed, and oil/gas reserves are used ahead of coal in order to reduce CO_2 emission rates.

Under these extreme assumptions, coal is still necessary as an energy source in the coming century. In other words, the world cannot realistically meet future energy demand needs without using coal.

5.1.2 Canadian Resources

Canada has abundant energy resources. The main types can be summarized as follows:

Hydroelectricity

Total installed capacity in 1988 was 57 GW, with 46 GW of planning potential remaining (EMR, 1989a).

Uranium

Measured reserves were 70 kt in 1986, with additional indicated reserves of 235 kt. Production in 1986 was 11.5 kt, with domestic and export commitments to deliver 73 kt to 2020 and 62 kt to 2003 respectively (EMR 1982; EMR 1987).

Natural Gas

Remaining marketable established reserves of natural gas are roughly 2 trillion m^3 in Western Canada and 665 billion m^3 in frontier areas (EMR, 1988). Marketable production was 78 billion m^3 in 1987. In total, these reserves should last between 9 and 90 years.

Crude Oil

Reserves in 1987 were estimated at (NEB, 1988; EMR, 1988):

	Established	Technical Potential
W. Canada	730	1 441
Frontier	523	4 045
Total	1 253	5 486 (millions of m^3)

Production in 1987 was 71.3 million m^3. Canadian conventional oil resources should last between 8 and 43 years.

Coal

Recoverable coal reserves (6.6 Gt), mainly located in Western and Northern Canada, will last until the end of the next century at present production rates (70 Mt in 1988). Measured and inferred reserves are 20.8 Gt and 15 Gt respectively (CAC, 1987b; NEB, 1988; and EMR, 1989b).

Table 5-1 reviews Canadian coal reserves by province and coal type. The key characteristics of coals used for electricity production in Canada are summarized on Table 5-2. The coals vary widely in type and constituents, ranging from the high quality bituminous coals used in Eastern Canada to the low rank sub-bituminous coals and lignite of Western Canada.

5.2 Canadian Electrical Energy 1988 to 2005

There are 16 major electric utilities in Canada, and some 60 industrial electricity generators. The Canadian electrical industry is organized along provincial lines. The following overview is drawn mainly from EMR (1989a).

5.2.1 Supply and Demand

Electricity production in Alberta, Saskatchewan and Nova Scotia is largely based on coal combustion. British Columbia, Manitoba, Québec and Newfoundland rely almost completely on hydroelectric resources. New Brunswick generates electricity from nuclear, oil and (to a lesser extent) coal. Ontario has

roughly equal proportions of fossil, hydroelectric and nuclear energy. Present provincial energy production by fuel type is shown on Table 5-3. Canadian electricity supply and demand data for 1988 to 2005 are summarized on Table 5-4.

About 489 TWh of electricity was generated in Canada in 1988, mainly for domestic use; roughly two-thirds was accounted for by Ontario and Québec alone. Electric utilities predict that electrical generation will grow by about 2.3% per year to 714 TWh in 2005. The National Energy Board (NEB) and Energy, Mines and Resources (EMR) forecasts are slightly lower (698 TWh) and higher (748 TWh) respectively.

Alberta and Ontario together produced almost 80% of Canadian coal-fired electricity in 1988. Principal coal-fired generating stations in Canada are listed on Table 5-5. Present utility projections to 2005 of electricity demand are for an overall growth of 2.2%. Again, the NEB and EMR forecasts are slightly lower (2%) and higher (2.4%) respectively.

The development of a database of historical and regional energy consumption patterns in the United States is described in EPRI EM-5126 (1987).

5.2.2 Generating Capacity

Installed electricity generating capacity in 1988 was 101 GW, about one-third fossil, over half hydroelectric, and the balance mainly nuclear. In a wider perspective, Canada ranks behind only the USA (719 GW), the USSR (322 GW) and Japan (173 GW) in generating capacity. Canada is the ninth largest operator of conventional thermal units.

Planned coal-fired additions to generating capacity are all conventional pulverized fuel (p.f.) units, except for possible circulating fluid bed (CFB) units in Nova Scotia. These are considered in detail in Section 8. Heavy fuel oil is used for steam generation in Nova Scotia, Newfoundland and New Brunswick, but plans call for reduced oil firing. Natural gas is used for steam generation in some regions, but plans are to reduce gas firing for base

load steam generation in power plants. Gas is used in several regions for peaking operation in combustion turbines.

5.3 The Canadian Coal Industry

Figure 5-1 overviews the Canadian coal industry in 1988, a year of records in which 28 mines employing roughly 12,000 people operated near capacity to produce 28 Mt of metallurgical coal and 42 Mt of thermal coal. Work forces are often very localized ; total revenue was in excess of $2 billion in 1988.

Coal Production and Consumption

Canadian coal supply and demand in 1988 is summarized on Table 5-6 (EMR, 1989a). Table 5-7 reviews inter-provincial coal trade in 1988 (CAC, 1989).

Canadian coal production was 71 Mt in 1988, the major producers being Alberta (34%, 29 Mt), B.C. (28%, 24 Mt) and Saskatchewan (14%, 12 Mt). Nova Scotia's underground collieries are labour intensive and expensive in comparison with western mine-mouth (open pit) operations, but continuous modernization has created an efficient and almost self-supportive industry. Coal exports from British Columbia (75% of market), Alberta (22%) and Nova Scotia (3%) amounted to 32 Mt. Most of this was shipped to Japan (63%) and South Korea (14%), with metallurgical coal constituting 86% of all exports.

Coal consumption in Canada was 54 Mt in 1988, 85% of which was used to generate electricity. A further 17 Mt of coal was imported from the USA. Coal usage by industry was fairly constant in the 1980's. No significant change is expected. The steel industry, mainly in Ontario, consumed 6 Mt of metallurgical coal in 1988, importing almost all of this from the United States. The cement, pulp & paper and manufacturing industries consumed about 2 Mt of thermal coal, again importing over half of this from the USA.

Coal Export Market

Canadian coal exports in 1988 are shown on Table 5-8 (CAC, 1989). World demand for metallurgical coal imports is currently 160 Mt per year. World thermal coal import demand was 176 Mt in 1986

The majority of Canadian metallurgical coal is shipped to Japan. Key growth areas are Brazil and the Pacific Rim countries of Korea and Taiwan. Energy policies of these Pacific Rim nations suggest large increases in their use of coal over the next 15 years (Section 4). Expansion of steel production in these countries is largely through the Basic Oxygen Furnace (BOF).

However, China also intends to increase its coal exports as much as possible. This, together with financial and technical assistance by Japan and others could significantly reduce the need of Pacific Rim countries for Canadian coal. South Korea's decision to expand its nuclear program, likely through CANDU-type reactors, may also impact coal trade to that country.

Projecting the future of coal export trends as they relate to Canada is clearly difficult. In an environment of relatively high world economic growth and oil prices, the growth in Canadian coal production could be substantial (NEB, 1988). Canada competes mainly with Australia, South Africa and the USA for the coal export market. The USA acts as a swing producer. New low-cost producers such as Columbia and China are also emerging.

Canada should be able to at least maintain present exports of metallurgical coal, and increase thermal coal exports by 3 to 5% (NEB, 1988). Projections for metallurgical coal demand trends estimate growth rates as high as 15 to 20% over the coming decade (Shell International, London, England). Other projections call for only modest growth rates, however; a U.S. Department of Energy suggests that 5% is more realistic (DOE, 1988). World thermal coal demand could grow to about 300 Mt by 2005 (NEB, 1988). The U.S. study projects a growth to 291 Mt by 2005 (DOE, 1988).

Further discussion of coal market outlooks can be found in CAC (1987a and b).

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TABLE 5-1: CANADIAN COAL RESERVES (Mt), 1988

Province	Coal	Recoverable	Measured*	Assured*
B.C.	Thermal	999		
	Metal.	1 563	3 045	4 710
Alta	Thermal	1 671		
	Metal.	240	15 785	7 250
Sask	Thermal	1 670	1 445	2 690
Ont	-	-	170	10
N.B.	Thermal	21	45	10
N.S.	Thermal	300		
	Metal.	115	300	355
Canada	Thermal	4 660 (71%)		
	Metal.	1 918 (29%)		
		6 578	20 790	15 025

*All coal

Sources: Canadian Energy Supply & Demand 1987-2005, NEB
Statistical Review of Coal in Canda, 1988, EMR

TABLE 5-2: CANADIAN COALS FOR ELECTRICITY PRODUCTION[1]

	ALBERTA	SASK.	ONTARIO[2]		N.B.	N.S.
			USA	W. CANADA		
Type	sub-bit.	lignite	bit.	bit.	bit.	bit.
Mining	strip	strip	u/g	strip/ug	strip	ug/strip
Coal prep.	--	--	wash	wash	--	wash
HHV MJ/kg as fired	17.70	15.38	30.34	25.64	26.33	28.0
Ash %	15.0		7.7	11.5	18.0	11.0
Moisture %	22.0	34.0	6.2	9.5	6.0	7.5
Sulphur %	0.3	0.6	1.7	0.3	8.5	2.8
Coal used in 1988 Mt	20.6	8.7	14.5		0.7	2.3
Proven resources of coal (measured) Mt	27,000	1,400	--	--	30	200

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[1] The above are typical values only. Actual values vary with coal sources within regions. ug = "underground"

[2] Ontario also uses lignite in the N.W. part of the province.

TABLE 5-3: 1988 ELECTRICAL ENERGY PRODUCTION (GWh) IN CANADA

	COAL	OIL	GAS	TOTAL FOSSIL
NFLD	0	1,419	0	1,419
P.E.I.	133	85	0	218
N.S.	6,033	1,752	0	7,785
N.B.	1,732	6,118	0	7,850
QUE	0	332	0	332
ONT	35,033	510	1,334	36,877
MAN	924	0	5	929
SASK	9,853	19	722	10,594
ALTA	33,627	120	4,994	38,741
B.C.	0	420	1,949	2,369
YUKON	0	30	0	30
N.W.T.	0	177	1	178
CANADA (FOSSIL)	87,335	10,982	9,005	107,322
NUCLEAR				78,176
HYDRO				303,546
TOTAL GWh				**489,044**

Source: Electric Power in Canada 1988, Table 4.2, Energy, Mines and Resources

TABLE 5-4: CANADIAN ELECTRICITY SUPPLY AND DEMAND 1988 TO 2005

Installed MW[1]	1988	2005	Increase	%
Coal	19,183	23,600	4,417	+23.0
Oil	7,311	8,285	974	+13.3
Gas	3,782	6,177	2,395	+63.0
Total Fossil MW	**30,276**	**38,062**	**7,786**	**+25.7**
Nuclear				
Hydro	57,484	77,505	20,021	+34.8
Total MW	**100,984**	**132,271**	**31,287**	**+31.0**
GWh Generation[2]				
Coal	87,335	146,677	59,342	+68.0
Oil	10,982	9,446	(1,536)	-14.0
Gas	9,005	23,556	14,551	+162.0
Total Fossil GWh	**107,322**	**179,679**	**72,357**	**+67.0**
Nuclear	87,975	114,578	26,603	+30.2
Hydro	303,546	413,388	109,842	+36.2
Total GWh	**489,044**	**713,884**	**224,840**	**+46.0**
Fossil Fuels Used[3]				
Coal 10^3 tonnes	47,270	77,116	29,846	+63.0
Oil m^3	2,491,752	1,867,864	(623,888)	-25.0
Gas 10^6 m^3	3,628	8,473	4,845	+134.0

Average annual growth rate 1988-2005 in MW capacity +1.6%[4]

Average annual growth rate 1988-2005 in GWh Generation +2.3%[5]

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[1] Table 10.4 Electric Power in Canada 1988

[2] Table 4.2 and 10.5 Electric Power in Canada 1988

[3] Table 10.7 Electric Power in Canada 1988

[4] Table 10.3 Electric Power in Canada 1988

[5] Table 10.5 Electric Power in Canada 1988

TABLE 5-5: PRINCIPAL COAL-FIRED POWER STATIONS IN CANADA, 1988

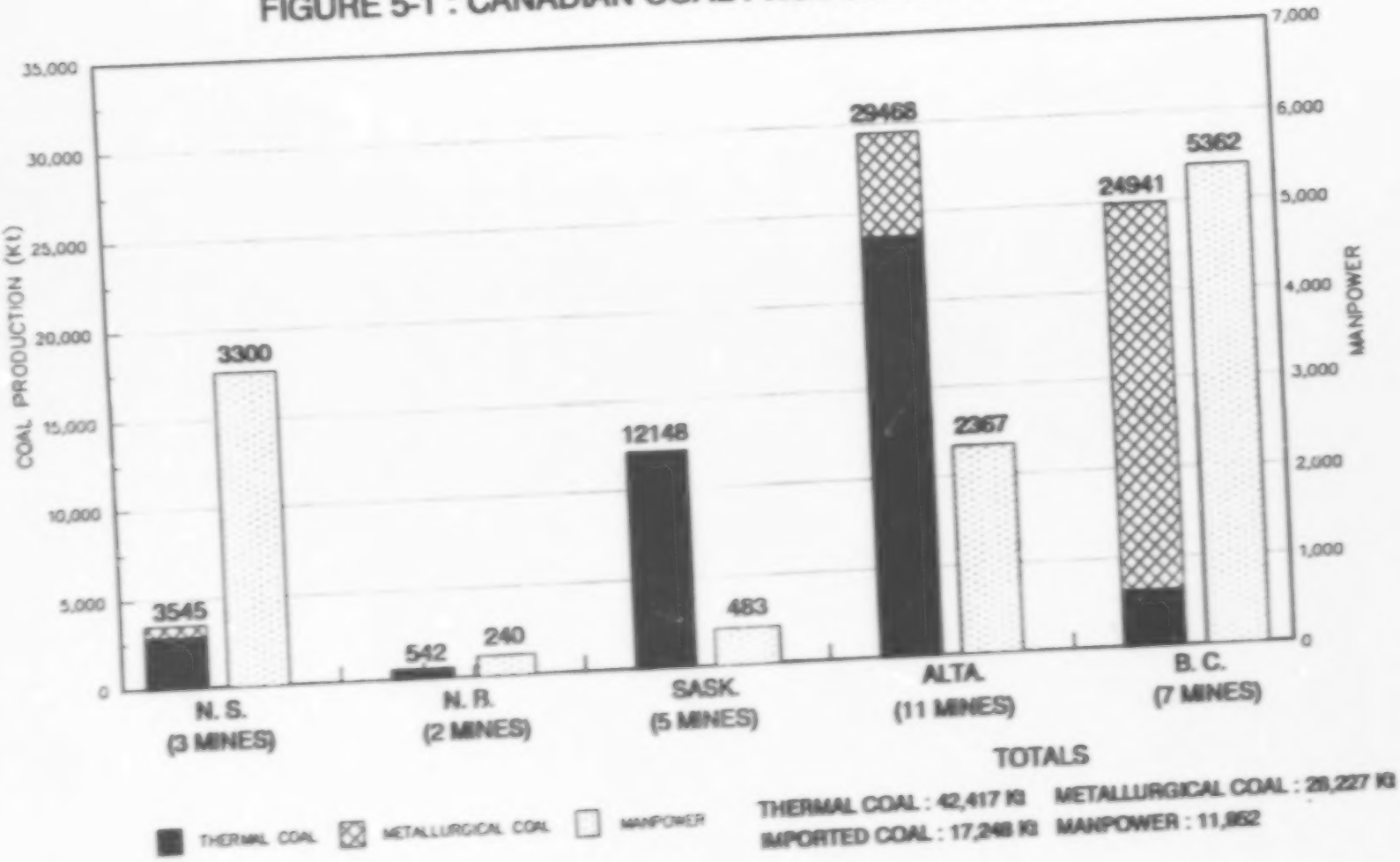
Station	Capacity (MW)	Coal Consumption (kt)
Nova Scotia		
Seaboard	96	117
Maccan	15	14
Trenton	210	305
Lingan	633	547
Point Tupper	229	252
	1 183	1 235
New Brunswick		
Dalhousie	200	478
Grand Lake	85	185
Chatham	32	15
	317	678
Ontario		
Lakeview	2 400	1 582
Nanticoke	4 000	6 414
Lambton	2 000	2 890
Thunder Bay	400	1 341
Atikokan	206	851
	9 006	13 078
Manitoba		
Selkirk	131	274
Brandon	237	506
	369	780
Saskatchewan		
Estevan	65	306
Boundary Dam	875	4 414
Poplar River	592	3 917
	1 532	8 637
Alberta		
Battle River*	740	3 160
H.R. Milner*	150	690
Wabamun*	582	2 959
Sundance*	2 200	8 639
Keephills*	806	3 376
Sheerness**	383	1 715
	4 861	20 539

* Alberta Power
* TransAlta Utilities

Total Capacity = 17 268 MW
Total Consumption = 44 947 kt

Source: Statistical Review of Coal in Canada, 1988, EMR

FIGURE 5-1 : CANADIAN COAL PRODUCTION IN 1988



TOTALS

THERMAL COAL : 42,417 Kt METALLURGICAL COAL : 28,227 Kt
IMPORTED COAL : 17,248 Kt MANPOWER : 11,862

TABLE 5-6: SUMMARY OF CANADIAN COAL SUPPLY AND DEMAND (kt), 1988

	Metallurgical	Thermal	All Coals
Production	28 227	42 417	87 892
Imports	6 255	10 993	17 248
Total Supply	34 482	53 410	87 892
Domestic Use	6 263	48 127	54 390
Exports	27 602	4 130	31 732
Total Demand	33 865	52 257	86 122

Source: Statistical Review of Coal in Canada, 1988, EMR

TABLE 5-7: INTER-PROVINCIAL COAL TRADE (kt), 1988

	FROM			
TO	N.S.	SASK	ALTA	B.C.
NEWF	0.3	-	-	-
PEI	6	-	-	-
N.B.	52	-	-	-
QUE	81	-	-	-
ONT	-	2 227	1 845	716
MAN	-	979	0.3	18
SASK	-	-	1	0.1
B.C.	-	-	1	-
	139	3 206	1 847	734

Source: Coal Association of Canada: 1988 Directory

TABLE 5-8: CANADIAN COAL EXPORTS (kt), 1988

Country	N.S. Met	N.S. Therm	Alta Met	Alta Therm	B.C. Met	B.C. Therm	CANADA Met	CANADA Therm	CANADA Total
Japan	-	196	4 551	1 199	3 517	533	18 069	1 928	19 997
S. Korea	-	-	336	-	2 878	1 332	3 214	1 332	4 546
Brazil	321	-	697	33	677	-	1 694	33	1 727
Taiwan	-	-	-	-	1 055	160	1 055	160	1 215
U.S.	-	47	-	-	773	-	773	47	820
E.E.C.	233	250	-	-	1 776	372	2 009	662	2 671
Others	-	-	-	-	590	-	590	-	590
	554	493	5 584	1 232	21 266	2 397	27 404	4 162	31 526
	1 047		6 816		23 663				

Source: Coal Association of Canada, 1988 Directory

6.0 CARBON DIOXIDE (CO_2) EMISSIONS IN PERSPECTIVE

6.1 Present and Projected Global CO_2 Emissions

The sources and sinks of CO_2 are better understood than those of other greenhouse gases. Global CO_2 emissions of CO_2 from anthropogenic sources have grown by about a factor of three over the past 40 years to about 20 Gt per year in 1988 (Appendix A6-1). The main source countries and their estimated CO_2 emissions in 1988 were (Task Force, 1989):

	CO_2 Emission (Gt)	%
USA	4.5	22
USSR	3.9	19
China	2	10
Japan	1	5

Models of the global economy are used to project future global demand of fossil fuels. These are reviewed in Appendix A6-2. Scenarios suggest that annual global fossil fuel CO_2 emissions could rise to as much as 70 Gt by 2050 if unrestricted. For a wide range of scenarios in which CFC's are phased out by 2003, a projected increase of atmospheric CO_2 will be responsible for 50% to 90% of the total predicted increase in greenhouse heat-trap strength (ΔQ) from 1980 to 2050.

6.2 Calculation of CO_2 Emissions

Emissions of CO_2 from a given fuel type are usually calculated by multiplying the total primary energy consumption for that fuel by an emission factor and by the fraction oxidized. Primary energy use and emission factors relate to either higher or lower heating values, however, and it is seldom indicated which is being used. UN historical data contain a gradual transition from lower to higher heating value-based data (Marland and Rotty, 1984).

Percentages of coal sulphur and ash directly affect emission of SO_2 and particulates, while N_2 from coal and combustion air contributes to NO_x emissions. Emission rates of CO_2 from various coals and other fossil fuels depend upon the:

- Amount of fuel burned, and the heating value of the fuel;
- Fuel type and constituents, particularly carbon content; and
- Fuel conversion process used and its efficiency (or station heat rate for electricity generating plants).

Gas, oil and coal fuels have different CO_2 emission levels due to differing hydrogen to carbon ratios. Efficiency of conversion of the heat energy stored in the fuel to electrical energy varies widely with both the conversion technology applied and the fuel type used.

Table 6-1 gives direct combustion CO_2 emission factors for various fuels for energy usages reported in terms of higher heating values. Emission factors for transportation fuels do not include emissions associated with refining. National Energy Board (NEB) projections account for the changing proportion of primary transportation fuels by including the equivalent secondary fuel amount used for refining (NEB, 1988).

6.3 Full Fuel Life Cycle CO_2 Emission Factors

Full fuel life cycle greenhouse gas emissions due to the generation of electricity include emissions during the extraction and processing of fossil fuels, their transportation to the power plant, and other factors.

For an overview assessment of utility CO_2 emissions, this study uses the mark-ups shown on Table 6-2, after Okken and Kram (1989). Site-specific mark-ups for a given power plant and fuel source must be used for a detailed assessment. For example, a mine-mouth plant in Alberta would have a much lower mark-up than a plant in Ontario which receives coal from several USA mines and wash plants and from Western Canada.

Under worst-case assumptions of leakage rates from natural gas distribution systems and if seepage from coal mines is minimal, switching to natural gas from coal remains advantageous from a greenhouse viewpoint (Appendix A6-3).

Also, substitution of gas for coal will result in greater production of water vapour, an important greenhouse gas. The perturbation to the hydrological cycle is negligible, however (see Appendix A6-4).

6.4 Canadian CO_2 Emissions By Province and Sector

Canadian total anthropogenic emissions of CO_2 from all sources were 471 Mt in 1987 (Jaques, 1989). Canadian CO_2 emissions for 1988, for which detailed data are not yet available, are estimated to have been 473 Mt (Task Force, 1989). Canada as a whole contributes about 2% of global CO_2 emissions (10.5% of USA total CO_2 emissions), but the third highest per capita CO_2 emission rate behind only the USA and East Germany.

Provincial (Direct Combustion) emissions of CO_2 in 1987 from all sources are shown in Figure 6-1 and on the below table (Jaques, 1989):

	(Mt)	%
Ontario	154	33
Alberta	105	22
Québec	64	14
B.C.	61	13
N.S.	17	4
N.B.	14	3
Saskatchewan	31	6
Others	25	5
	471	

Provincial emissions differ greatly in total and in those sectors responsible for the emissions. For example, utilities in British Columbia and Québec do not emit significant amounts of CO_2. These provinces together, however, produced over a quarter of Canadian CO_2 emissions from all sectors in 1987.

Large quantities of CO_2 are emitted from sources other than utilities and transportation. For example, direct CO_2 emissions in Ontario from industrial sources (45.0 Mt) and from residential and commercial sources (23.5 Mt) in 1987 correspond to 30% and 15% respectively of Ontario's total CO_2 emissions.

Estimated CO_2 Emissions by Sector in 1987 are (Jaques, 1989):

	(Mt)	%
Fuel Combustion - Stationary Sources*	260	55.3
Fuel Combustion - Transportation	143	30.4
Industrial Process Sources	41	8.8
Solid Waste Incineration	10	2.2
Slash Burning	16	3.3
	471	

* CO_2 emissions in this category are from industrial sources at 70 Mt (15%); residential and commercial sources at 59 Mt (13%).

The Pulp & Paper Industry emitted about 31 Mt of CO_2 (7%) in 1987, mainly through combustion of spent pulping liquors.

The Cement Industry generated about 6 Mt of CO_2 in 1987, through coal combustion and the reduction of limestone ($CaCO_3$).

The Ammonia Industry, using the Haber-Bosch process for manufacturing ammonia (NH_3) relies largely on natural gas, and produced about 4 Mt of CO_2 in 1987.

Canadian Industrial (non-utility) consumption of coal and corresponding CO_2 emission estimates for 1988 are:

	Mt Coal	Mt CO_2
Steel:	6.26	17
General:	1.85	5

CO_2 Emission Projections for 2005

Projections of national CO_2 emissions in 2005 differ, as follows:

Energy, Mines and Resources (EMR)	= 706 Mt
National Energy Board (NEB) - low energy use scenario	= 601 Mt
- high energy use scenario	= 649 Mt

The NEB econometric energy demand model is similar to EMR's Inter-Fuel Substitution and Demand (IFSD) model. The NEB also uses a structural model of the residential and industrial sectors. Different assumptions are input to the two approaches, and the NEB results are at least as credible as the IFSD model forecast. Present projections of energy use to 2005 do not take global warming concerns into consideration, however, although the next NEB projection will do so (E. Ruddick, NEB, Pers. Comm., Sept 1989).

The NEB projections of national primary fossil-based energy use and the corresponding direct CO_2 emissions are shown on Table 6-3 (NEB, 1988). Primary energy demand includes utility demand, end use demand, own use and conversion of coal into coke. Natural gas accounts for a large share of the fossil fuel increase, so the relative increase of emissions due to electric power production is smaller than the relative increase in electric energy from fossil fuels.

6.5 CO_2 Emissions from Canadian Utilities

A major anthropogenic source is the combustion of carbon in a fuel. This forms typically about 12% to 15% CO_2 by volume in flue gas from a large utility boiler burning bituminous coal. The remaining flue gas is largely nitrogen (N_2).

Full cycle CO_2 emissions from electricity generation are given by fuel type on Table 6-4. Full fuel cycle CO_2 emissions from Canadian electric utilities in 1988 were about 122 Mt, about a quarter of national emissions. Present (1988) projected (2005) utility CO_2 emissions were estimated from reported utility planned capacity additions (EMR, 1989) and from utility responses to questionnaire. The estimates are:

Full-Cycle Utility CO_2 Emissions (Mt)

	1988	2005*
Ontario	39.1	39.1
Alberta	47.5	74.0
N.S.	8.5	15.1
N.B.	7.7	15.2
Saskatchewan	14.1	19.7
Others	5.0	12.7
	121.9	175.8

* A preliminary assessment of Ontario Hydro's Demand/Supply plan suggests that an additional 10.7 Mt of CO_2 emissions can be expected by 2005.

The key points for the present distribution of utility CO_2 emissions are that:

- Utilities contribute about a quarter of national CO_2 emissions;
- Coal is the predominant source of CO_2 (87%);
- Alberta and Saskatchewan contribute half of the Canadian total;
- Ontario contributes one-third; and
- New Brunswick and Nova Scotia together contribute 13%.

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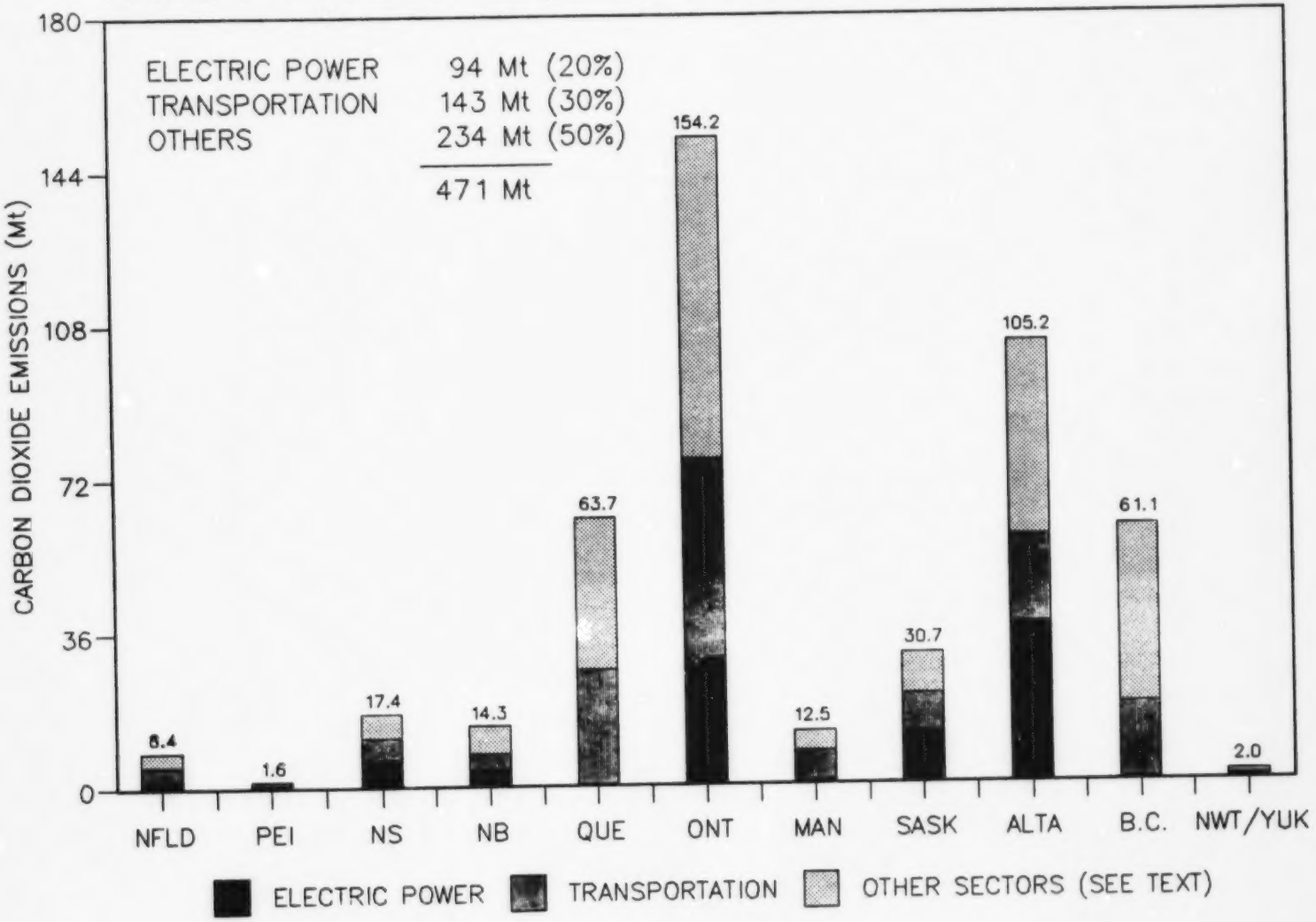
TABLE 6-1: FUEL CO_2 DIRECT COMBUSTION EMISSION FACTORS (t/TJ)

FUEL	EMISSION FACTORS	
	CARBON	CO_2
GASEOUS		
Natural Gas	13.55	49.68
LIQUID		
Motor Gasoline	18.54	67.98
Kerosene	18.56	67.65
Aviation Gasoline	18.92	69.37
Propane	16.32	59.84
Diesel Oil	19.28	70.69
Light Oil	19.94	73.11
Heavy Oil	19.51	71.54
Aviation Turbo	19.32	70.84
SOLID		
U.S. Bituminous	23.44	85.95
Cdn. Bituminous	23.65	86.72
Sub-Bituminous	25.69	94.20
Lignite	27.73	101.68
Anthracite	23.44	85.95
Fuel Wood	22.22	81.47
Slash Burning	22.22	81.47
Incineration	0.25 t/t of refuse	0.90 t/t of refuse
INDUSTRIAL SOURCES		
Cement Production	0.14 t/t of cement	0.50 t/t of cement
Ammonia Production	0.43 t/t of ammonia	1.58 t/t of ammonia
Pulp & Paper Production	29.29	107.38

Combustion of 1 tonne of carbon gives 3.67 tonnes of CO_2

Source: Jaques, 1989

FIGURE 6–1 : PROVINCIAL (DIRECT COMBUSTION) CO_2 EMISSIONS IN 1987



SOURCE: Jaques, 1989

TABLE 6-2: DIRECT COMBUSTION - FULL FUEL CYCLE CO_2 EMISSION RATES

FUEL	CO_2 EMISSION grams/MJ				% INCREASE FROM DIRECT TO FULL CYCLE
	DIRECT COMBUSTION	INDIRECT CO_2	CH_4/CO AS CO_2	FUEL CYCLE	
COAL	94	3	11 (4 to 18)	108	14.9
OIL	75	10	8 (6 to 11)	93	23.5
GAS	56	3	8 (5 to 13)	67	19.6

"Indirect CO_2" includes emissions such as those from coal mining and handling, from oil refining operations, and from gas used for pipeline compressors.

"CH_4/CO as CO_2" is CO_2 formed when methane is oxidized (via CO) in the atmosphere. Leakage of natural gas systems is taken as 2.1%.

Source: "CH_4/CO - emission from fossil fuels global warming potential" by P.A. Okken and T. Kram, Energy Study Centre, Netherlands Energy Research Foundation. Prepared for IEA/ETSAP workshop, Paris, June 1989.

TABLE 6-3: CANADIAN FOSSIL-BASED PRIMARY ENERGY USE AND DIRECT CO_2 EMISSIONS

	TOTAL PRIMARY ENERGY (PJ)			EMISSIONS (Mt CO_2)		
FUEL	1986	2005 LOW	2005 HIGH	1986	2005 LOW	2005 HIGH
Oil	3,066	3,668	3,759	184	221	226
Natural Gas	2,064	2,913	3,231	105	150	166
Nat. Gas Liquids	151	233	244	-	-	-
Coal	1,040	1,517	1,958	91	144	171
Fossil fuel total				**380**	**144**	**563**
Total				**458**	**601**	**649**

Source: National Energy Board (NEB, 1988; Tables 4-16 to 4-19)

HIGH = NEB high energy use scenario

LOW = NEB low energy use scenario

TABLE 6-4: FULL CYCLE CO_2 EMISSIONS (Mt) BY CANADIAN UTILITIES IN 1988

	COAL	OIL	GAS	TOTAL	%
NEWF.		1.36		1.36	
PEI	0.14	0.08		0.22	
N.S.	6.81	1.68		8.49	7.0
N.B.	1.78	5.87		7.65	6.3
QUE.		0.32		0.32	
ONT.	37.84	0.49	0.80	39.13	32.0
MAN.	1.28	--	--	1.28	
SASK.	13.60	0.02	0.43	14.05	11.5
ALTA.	44.39	0.12	3.00	47.51	39.0
B.C.		0.40	1.17	1.57	
YUKON		0.03		0.03	
NWT		0.17		0.17	
CANADA	105.84	10.54	5.40	121.78	
			SAY	122 Mt	
PERCENT	87 coal	8.7 oil	4.4 gas		

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7.0 ASSESSMENT OF TECHNOLOGY ALTERNATIVES

7.1 Fossil Based Generation Technologies Available to 2005

A range of technologies were assessed for their potential to reduce CO_2 emissions, including factors such as:

- Applicability (capacity, operation modes, regional factors);
- Costs and timing (commercial readiness and installation time);
- New and retrofit suitability; and
- Other environmental considerations.

The main fossil-fuel based utility scale electricity generation technologies available for in-service dates to 2005 are:

- Conventional Coal-Steam
- Conventional Oil-Steam
- Conventional Gas-Steam
- Cogeneration
- Integrated Gasification Combined Cycle (IGCC) using coal
- Fluidized Bed Combustion (FBC) using coal
- Gas (Combustion) Turbines
- Phosphoric Acid Fuel Cells (PAFC) (smaller capacity only)

Table 7-1 and Figure 7-1 show CO_2 emission rates in kg per kWh. The major options to reduce CO_2 emissions are:

- Using coal in higher efficiency processes, such as IGCC or PFBC;
- Using gas turbine/combined cycle options;
- Conversion to gas from coal; and
- Cogeneration.

It is important to note that control of SO_2, NO_x and particulate emissions must also be considered, together with other technical and economic factors.

TABLE 7-1: CO_2 EMISSION RATES (kg/kWh) FOR AVAILABLE TECHNOLOGIES AND FUELS

TECHNOLOGY	FUEL	ASSUMED EFFICIENCY %	------EMISSIONS----- DIRECT COMBUSTION	FULL CYCLE
Coal-steam	NS Bitum.	32.4	0.98	1.13
Coal-steam	NB Bitum.	31.5	0.89	1.03
Coal-steam	US Bit (Ont)	34.0	0.92	1.06
Coal-steam	W Can/US Bit	34.0	1.00	1.15 (Note 7)
Coal-steam	Sask Lignite	28.3 - 30.0	1.20 - 1.13	1.38 - 1.30
Coal-steam	Alta Sub-Bit	30.9 - 35.0	1.15 - 1.04	1.32 - 1.20
Coal-IGCC	Bituminous	39.0	0.80	0.92
Coal-IGCC	Sub-Bitum.	39.0	0.85	0.98
Coal-PFBC	Bituminous	40.8	0.83	0.95
Oil-steam	# 6	34.0	0.77	0.96
Gas-steam	Natural Gas	35.0	0.51	0.62
Gas turbine - simple cycle		29.0	0.62	0.74
Gas turbine - combined cycle		45.0	0.40	0.48
Gas turbine - Aero/STIG		40.0	0.45	0.54
Gas turbine - Aero/ISTIG (Gas)		47.0	0.38	0.46
Cogeneration - coal/steam		50.0	0.68	0.78
Cogeneration - gas comb. cycle		80.0	0.21	0.26
Cogeneration - gas/steam		50.0	0.36	0.43

Notes to Table 7-1

1. Present CO_2 emission rates per kWh have been assumed on a province-wide basis in order to estimate total CO_2 emissions for each province. A single fuel heating value and station heat rate for each region is applied.

   Specific emission rates must be assessed when evaluating new or retrofitted units with appropriate fuel characteristics (HHV and carbon content), and efficiencies (unit heat rates).

2. "Full fuel cycle" CO_2 emission rates are Direct Combustion Rates multiplied by (see Table 6.2):

   Coal: x 1.15
   Gas: x 1.20
   Oil: x 1.24

   These are average mark-ups values only. Local assessments will vary with specific fuel and operation.

3. References used in compiling Table 7-1 are given in the main text. Questionnaire-based input was also received from the main regions using fossil fuel for electricity generation.

4. Data for fuel cells and for CO_2 capture/disposal options are given in Appendix A7.

5. Figure 7-1 shows the main data from this table pictorially

6. For fluid bed options requiring limestone for SO_2 reduction, a CO_2 penalty due to calcining of the $CaCO_3$ would apply. The emission rates shown here do not include this, since the penalty depends to a large extent on the amount of sulphur in the coal.

7. The Nanticoke 4 GW coal-fired station of Ontario Hydro uses a blend of USA and Western Canadian bituminous coals in order to reduce SO_2 emissions.

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Oil-steam	# 6	34.0	0.77	0.96
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Gas turbine - simple cycle		29.0	0.62	0.74
Gas turbine - combined cycle		45.0	0.40	0.48
Gas turbine - Aero/STIG		40.0	0.45	0.54
Gas turbine - Aero/ISTIG (Gas)		47.0	0.38	0.46
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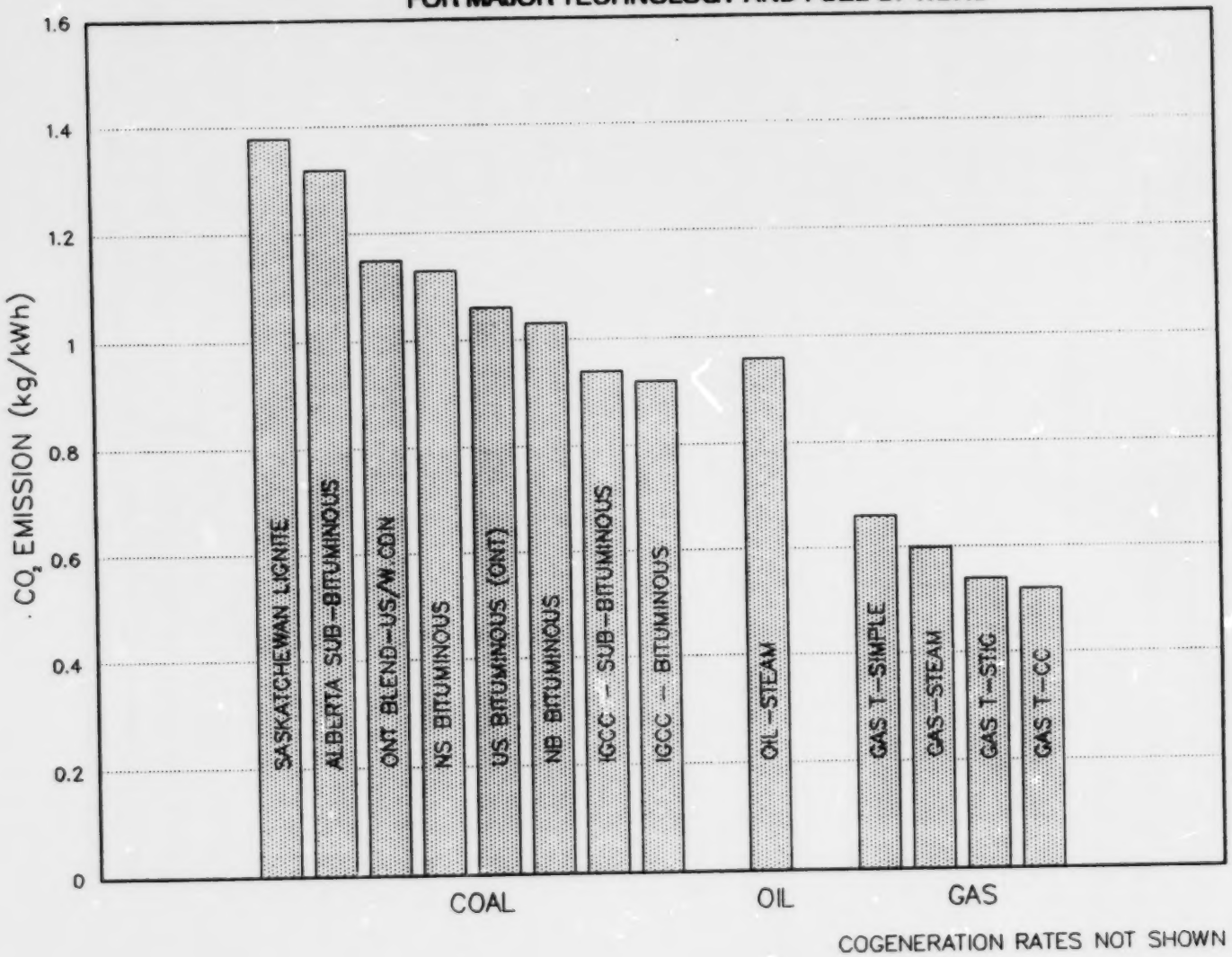
FIGURE 7-1 : FULL CYCLE CARBON DIOXIDE EMISSION RATES FOR MAJOR TECHNOLOGY AND FUEL OPTIONS



7.1.1 Fuel-Steam Conventional Units

These stations use steam turbines to produce power. Only improvements in overall plant efficiencies, now typically 30% to 35%, will further reduce CO_2 emissions. Conventional plants already operate at or close to optimum levels and significant reductions in CO_2 emissions are unlikely to be achieved through efficiency improvements.

Figure 7-2 shows a schematic diagram of the conventional steam cycle. Heat is lost to the cooling water at the low pressure end of the cycle. The availability of cooling water for the condensers is an important issue in siting plants; large man-made or natural lakes, located close to coal operations, are used in Western Canada.

Coal is the main fuel, with oil and gas used in only a few plants in the Maritimes and in Western Canada respectively. Canada has large reserves of inexpensive thermal coal, especially in Saskatchewan, Alberta and British Columbia. Ontario uses imported USA and Western Canadian coals. Nova Scotia and New Brunswick use local coals for most of their fossil fuel power production.

Specific coal and ash characteristics are key inputs to boiler and power plant design for each region (Burnett, 1976; Lethbridge, 1982; Winship et al., 1980; and EPRI CS-5936-SR, 1988). Units of up to 500 MW capacity are in service in Canada. Each is designed to burn a specific and limited range of coals, and a large new coal-fired plant takes 4 to 5 years to construct. Fossil fuel units provide a necessary degree of flexibility in generating options, and the reliability needed in operating large generating units.

At present, the firing of gas for conventional steam turbine units is limited. Gas is used for peak load steam generation, for cycling loads and for stabilizing coal furnaces at low loads. Gas can be used for base load operation, providing clean, flexible operating conditions and eliminating the need for SO_2 control equipment, for coal handling and storage, and for ash handling and disposal facilities. Gas can also be used in cogeneration

configurations.

Gas firing in steam generators is applicable to all plant sizes in regions where gas is available. Political decisions have, however, limited the availability of gas in some provinces, for example Alberta. The technology is used by many utilities, especially in the U.S. Gulf states. Plant conversion to gas-firing is straightforward and can be quickly implemented.

Ontario Hydro plans to re-commission two gas-steam units at the R.L. Hearn generating station by Fall 1991. New gas-steam units are unlikely to be committed in the future, however, since gas combined-cycle configurations offer faster, cheaper and more efficient production.

New conventional oil-steam units are not considered in this study.

7.1.2 Cogeneration

Cogeneration, using any fuel, will greatly reduce CO_2 emissions per kWh compared to a conventional coal-steam unit, especially with a gas combined-cycle configuration. Commercial scale technology is available, and can be applied more quickly than conventional power plants.

Cogeneration provides industry with an alternative to purchasing electricity from a utility and fuel from outside sources. Larger plants may be based upon steam turbine or gas turbine generators. Figures 7-3 and 7-4 show typical cogeneration fuel-steam and combined cycle gas/steam turbine configurations respectively. Figure 7-5 shows the gas turbine/heat recovery cycle without a steam turbine. Many cycle variations are possible, some using new technologies, which can optimize the project overall heat balance.

Fuels and configurations for cogeneration are selected so that overall plant design matches heat loads with electricity loads for the daily and seasonal demand patterns of the industry. Overall cogeneration plant efficiencies are

typically 50% to 80%, depending on the use of the low grade heat. Heat losses to the condenser cooling water are minimized or eliminated.

Industries use waste heat or waste materials to generate process steam, often with cogeneration of electricity. Kraft pulp mills, for example, generate large quantities of steam from "black liquor" firing in their chemical recovery boilers and from bark and other waste materials in their "power boilers". Municipal waste incinerators provide district (space) heating and power needs in Scandinavia, Japan and elsewhere. Incinerating waste has the additional advantage from a greenhouse gas emission viewpoint that methane emissions from landfill are thus avoided.

Canada's existing cogeneration plants are mainly operated by chemical process industries, pulp and paper mills, steel mills and petroleum processing plants, including tar sands processing. Large industrial cogeneration plants typically range from 20 MW to 100 MW. Ontario produces roughly 500 MW of electric power through fossil fuel cogeneration, and the 161 MW gas turbine combined cycle plant operated by Dow Chemical in Sarnia is the largest in Canada.

The Ontario Ministry of Energy's Cogeneration Source Book (Ont. MOE, 1988) gives useful basic data on cogeneration projects. Further prospects for Ontario and other areas are discussed in Shalaby (1986) and Basta and Price (1985).

Legislative changes and tax incentives in the U.S. aim to ensure that a significant part of new U.S. electricity will be generated by cogeneration plants, and several major projects are either in service or planned. The independent power industry in the USA currently contributes 26,300 MW of fossil capacity (Modern Power Systems, May 1989, p3).

Cogeneration units can be built more quickly than conventional power plants. A steam/power plant can be built for a large pulp mill in 2¼ to 3 years, and industrial process plants can be retrofitted with large cogeneration units

in only 1½ to 2 years. Cogeneration units cannot normally be applied to a conventional power plant or to an industrial plant, however, unless a suitable user of (i.e. sink for) the waste heat can be located alongside.

Cogeneration will result in a partial transfer of responsibility for future electricity generation from utilities to cogenerators, with ramifications for regulation, regional planning and environmental control.

Ontario Hydro's recent 25 year Demand/Supply plan includes new hydro and fossil generation together with "11 Non Utility Generator (NUG) projects totalling 172 MW under construction, 23 NUG projects totalling 216 MW indicated by their developers as committed to construction. New additions by 2014 will amount to about 2,100 MW, and there will likely be a total of about 3,500 MW in existence by that time" (Providing the Balance of Power, Ontario Hydro, Dec 1989).

7.1.3 Integrated Gasification Combined Cycle (IGCC)

An IGCC power plant gasifies raw coal, using air or oxygen, firing the gas in a gas turbine combined cycle unit to produce electricity (Figure 7-6). Efficiencies of about 39% are predicted for the combined cycle configuration and, if gas turbine designs and materials are advanced to accept higher inlet gas temperatures, will further improve, possibly to 42%. IGCC is a clean-coal technology (reducing SO_2, NO_x and particulate emissions) which also reduces CO_2 emissions due to its higher efficiency.

IGCC plants of some 380 MW capacity are promised for the late 1990's on a fully commercial basis, and utilities are mostly considering adoption of this technology on a phased basis. The gas turbine or gas turbine combined cycle initial phases do not need long lead times.

Pilot testing of coals is necessary prior to detailed design of a coal gasification plant. Where oxygen is used in the gasifier, significant power is needed in the air separation plant.

The Cool Water project in California operated a 100 MW unit from 1984 to 1989, testing various coals; the gasifier is Texaco's oxygen blown type and project sponsors include Southern California Edison, EPRI, General Electric and Bechtel. It is currently shut down, but Texaco plans to bring it into full commercial operation by 1991 firing a mixture of coal and sewage sludge.

Shell Oil has conducted an extensive IGCC test program in Texas with their own gasifier, and now offer units of almost 400 MW in capacity. Shell has tested sub-bituminous coals from the Powder River basin, similar to Alberta coals.

Dow Chemical commissioned an IGCC plant in Louisiana in 1987 with two 100 MW gas turbines partially fired by gas-from-coal produced in a Dow gasifier plant (Power magazine, Oct 1989). Complete Canadian IGCC units could be committed for the mid-1990's for 400 MW capacity.

IGCC plant operation is closer to that of a chemical process plant rather than a conventional power plant. Electricity production criteria, such as the capacity factor and operation modes, must be matched to the gasification plant size, design and operation. IGCC plants remove other pollutants, such as SO_2, in the gasification plant prior to delivery of fuel gas to the power plant. In some cases, a chemically inert slag suitable for road aggregate is the end product.

Coal characteristics and preparation processes affect the selection of the type of gasifier. Possible CO_2 removal from the coal gasification processes used in IGCC is addressed in Appendix A7-5.

Most IGCC plants now in the preliminary study stage are based on very large gas turbines (150 MW) for which there are further technology advances and proving periods with base load operation still to be evaluated.

In summary, IGCC appears to be an important coal-using technology to consider

for units up to about 400 MW for in-service dates in the late 1990's, with the gas turbine phase preceding the coal phase.

A comprehensive study for IGCC projects in Nova Scotia, Ontario and Alberta has recently been completed (CEA, 1989a). The advantages and disadvantages of IGCC are also discussed in CEA (1989b) and EPRI AP-5950 (1988).

7.1.4 Fluidized Bed Combustion (FBC)

FBC units burn coal in a "fluid bed" of solids suspended by combustion air blown upwards in a suitable vessel. Where necessary, limestone ($CaCO_3$) is added to the fluid bed to react with sulphur in the coal, so that most sulphur is removed with the ash. This avoids the need for Flue Gas Desulphurization (FGD), as used on a conventional boiler, but the calcining of the limestone releases CO_2 additional to that resulting from combustion of the coal. The amount of limestone added depends upon the percentage of sulpur in the coal, and can be considerable. Western Canadian coals are, however, low in sulphur.

The main versions of FBC are:

- Atmospheric Bubbling FBC: the AFBC vessel is maintained at atmospheric pressure;
- Atmospheric Circulating FBC: hot gas and solids leaving the CFB combustor vessel are re-circulated to allow further burning in the fluid bed.
- Pressurized FBC: the PFBC vessel is maintained at a pressure of at least 4 atmospheres, so that the combustion and heat transfer reactions proceed at faster rates; and

FBC technologies are clean coal processes selected to control SO_2 and NO_x emissions, which can use very low and variable rank coals. CO_2 emission per

kWh for a given coal are higher for atmospheric FBC, but are reduced for PFBC due to the higher efficiency.

Heat from the fluid bed is extracted by immersed steam tubes or by using the hot exhaust gases in various ways. With PFBC (Figure 7-7), the hot exhaust gases from the combustor pass through particulate-removal devices, and then flow to the gas turbine of a combined cycle plant. PFBC can include embedded heat exchange tubing to produce steam for the turbine, augmenting that from the heat recovery steam generator (HRSG) at the gas turbine exhaust.

The temperature in a PFBC vessel is limited to below ash agglomeration temperatures (about 950°C) and to allow appropriate temperatures for sulphur capture (about 850°C). NO_x formation is also reduced due to the much lower flame zone temperatures compared to a conventional pulverized coal furnace.

FBC technology is well established for industrial boilers using atmospheric pressure beds to generate steam. Considerable progress has been made towards utility fluid bed application. TVA operate a 160 MW demonstration AFBC unit, and American Electric Power will commission a 73 MW PFBC unit in 1990. A 20 MW CFB unit is also in operation at Chatham, New Brunswick, testing various Canadian coals, including those for a 165 MW ACFB unit now being designed for Nova Scotia.

BC Hydro has carried out detailed studies on possible PFBC application for (future) Hat Creek coal. PFBC will likely be established as a commercially proven technology for units entering service after year 2000. Lead time estimates should allow for thorough pre-testing of proposed coals in demonstration modules.

The advantages and disadvantages of FBC are also discussed in CEA (1989b) and EPRI CS-5296 (1987).

7.1.5 Gas (Combustion) Turbines

Gas turbines directly convert heat energy from combustion to mechanical energy, driving an electricity generator and an air compressor. Combustion takes place at high pressure in a combustor before the hot gases pass through the turbine.

Advanced gas turbines offer multiple benefits for power generation over the next 2 to 4 decades (Williams, 1988). In addition to reducing power costs, SO_2 and particulate emissions are very low when using either gas or distillate fuel; NO_x emissions are controlled by moisture injection or back-end removal.

Gas turbine cycles are used in several configurations and can make use of existing power plant equipment. They are operationally flexible and are suited for use in cogeneration plants where natural gas is available. Distillate oil and coal-derived gas can also be used as fuel, as in the IGCC configuration. Direct coal-firing of gas turbines with pre-cleaned coal is not yet a commercially available technology. PFBC also allows the use of coal as fuel for gas turbines/combined cycle generating units.

Gas turbine units eliminate (with simple cycle) or significantly reduce (combined cycle) condenser cooling water requirements and the need for coal handling and ash disposal facilities. Table 7-1 and Figure 7-1 show the significantly lower CO_2 emission rates of gas turbine configurations.

In simple cycle gas turbines (Figure 7.8), no heat is recovered from the exhaust gases. Combined cycle configurations (Figure 7.9), however, allow heat to be recovered from the exhaust gases in a Heat Recovery Steam Generator (HSRG), and the steam drives an adjacent steam turbine. Many gas turbine/HRSG installations produce steam for process use rather than for steam turbine generators (Figure 7-5).

Lower capacity "aero-derivative" machines based on aircraft jet engines are available. These have increased power and higher efficiencies than simple cycle configurations. Examples, shown in Figure 7-10, include steam injection

(STIG), and Inter-cooled Steam Injection (ISTIG).

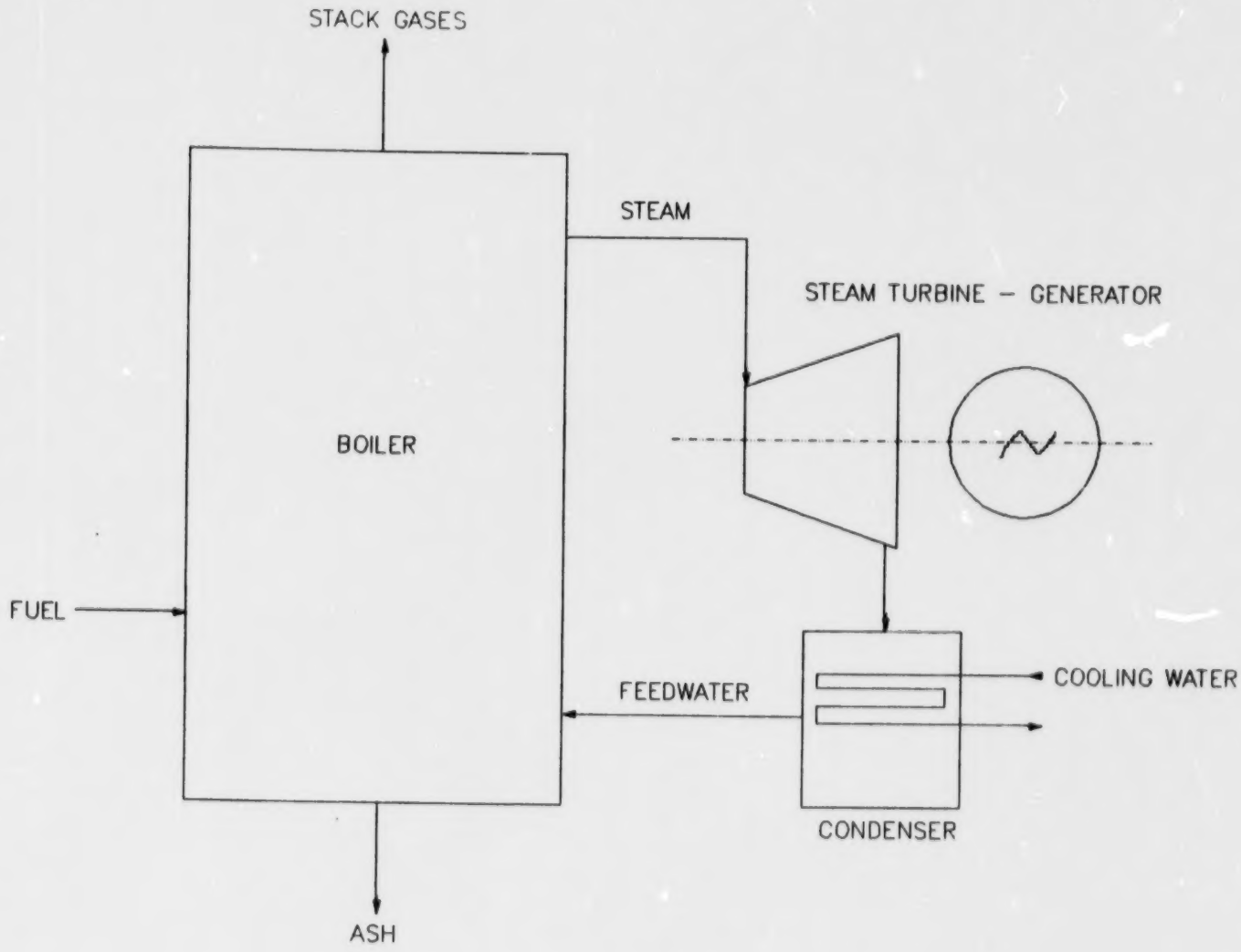
Single industrial gas turbine-generators up to 150 MW in capacity are now coming into service. They have high exhaust temperatures and are well suited to combined cycle operation. Combined cycle units up to 400 MW capacity are in commercial service, and aero-derivative gas turbines for advanced simple cycle applications are available in sizes up to about 35 MW. Although they have not been used extensively for base load production, gas turbine units can be designed for such operation, and they offer flexibility for other modes of plant operation, such as cycling.

Gas turbines can be retrofitted at sites where gas (or distillate oil) is available. They can be combined with some of the existing steam plant, for example in a combined cycle retrofit as shown in Figure 7.11.

Turbine inlet temperatures in excess of 1,200°C are available, compared with the maximum inlet temperature of 540°C in present steam turbines. Development work by suppliers is advancing rapidly to bring higher efficiency units with higher turbine inlet temperatures, to the market. STIG is available now, but ISTIG has still to be commercially applied. A large industrial gas turbine can be in service about 20 months from order.

7.1.6 Phosphoric Acid Fuel Cells (PAFC's)

PAFC's are electro-chemical devices which generate electric power from oxidation of natural gas. Efficiencies of 40% to 45% are expected, thus reducing CO_2 emissions in comparison to coal-steam units. 100 MW PAFC power plants could be available by the late-1990's. Fuel cells are quiet, modular units with short installation times and low SO_x and NO_x emissions. They can quickly be added to utility capacity as need be. Further detail is provided in Appendix A7-4.


STACK GASES
STEAM
STEAM TURBINE – GENERATOR
BOILER
FUEL
FEEDWATER
COOLING WATER
CONDENSER
ASH

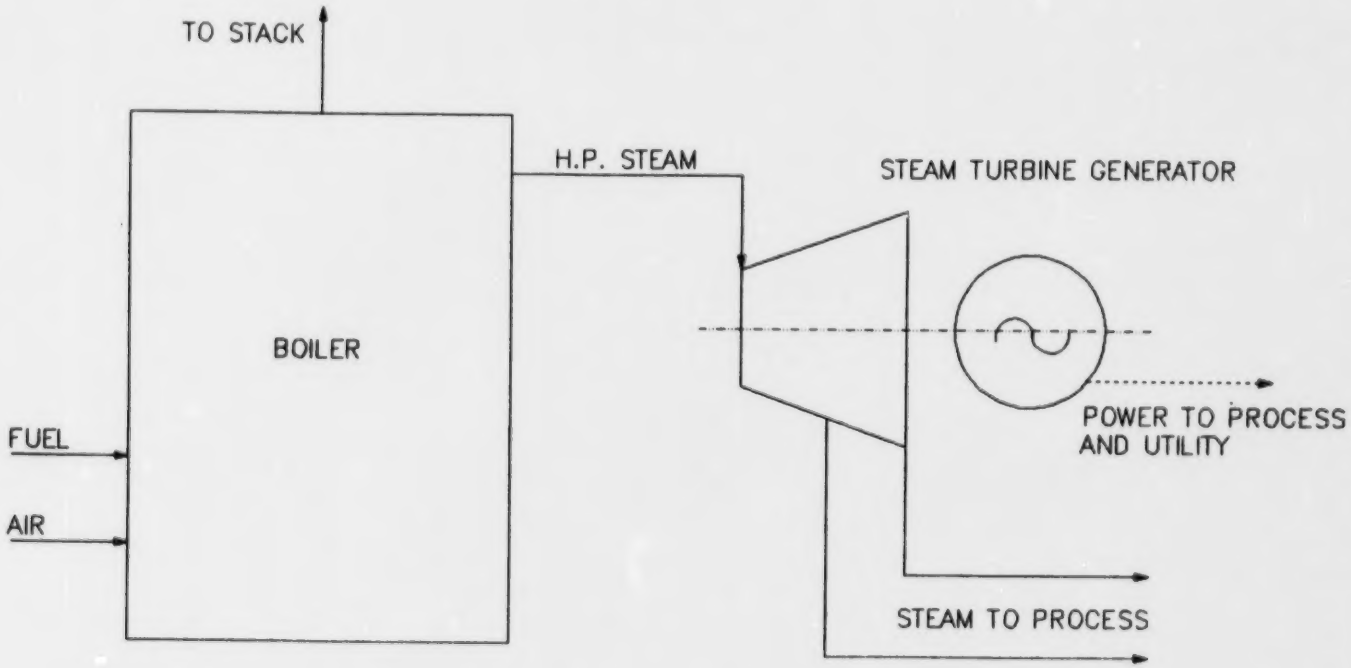


FIGURE 7-3. Cogeneration - steam cycle

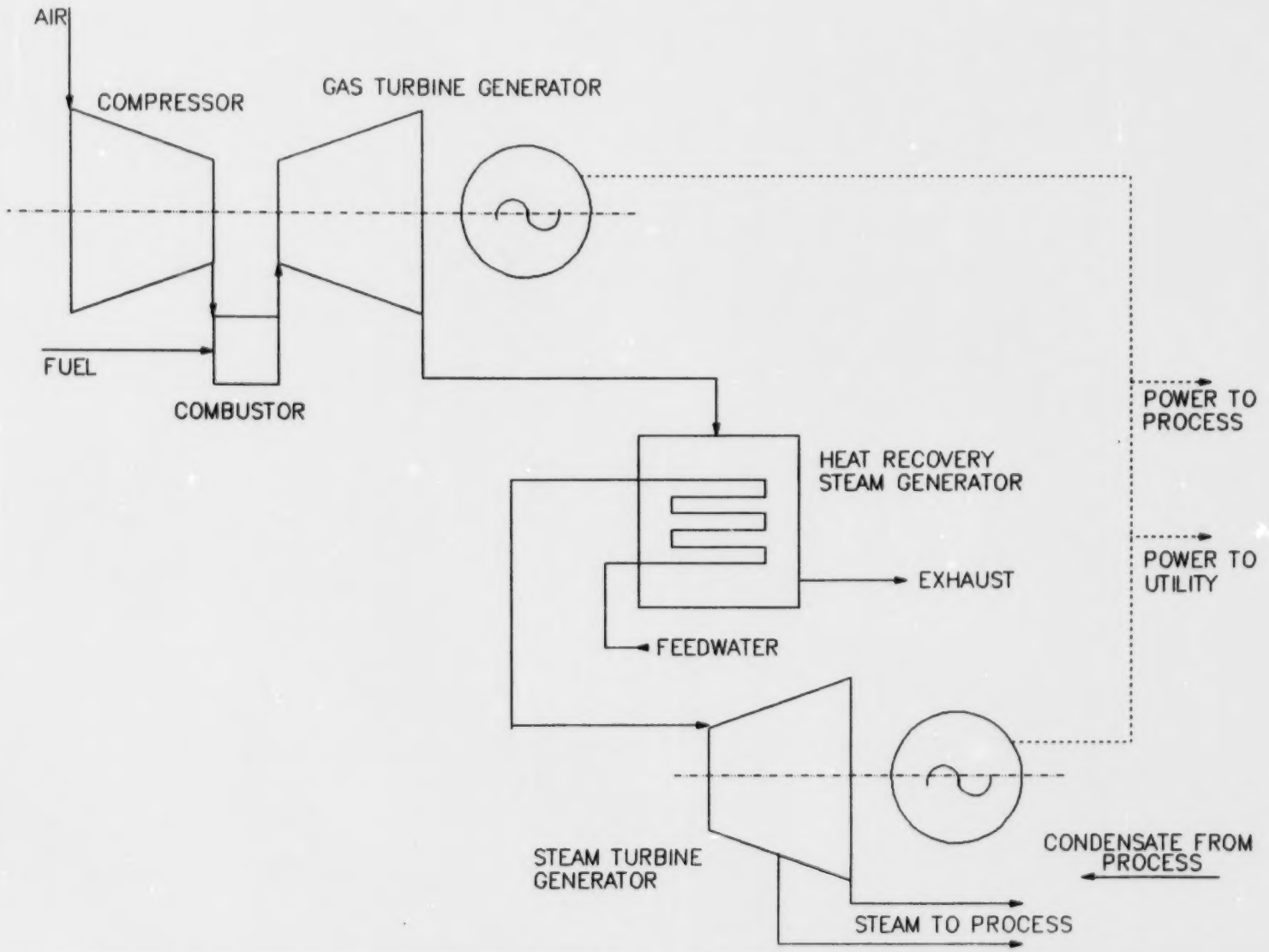


FIGURE 7-4. **Cogeneration - combined cycle**

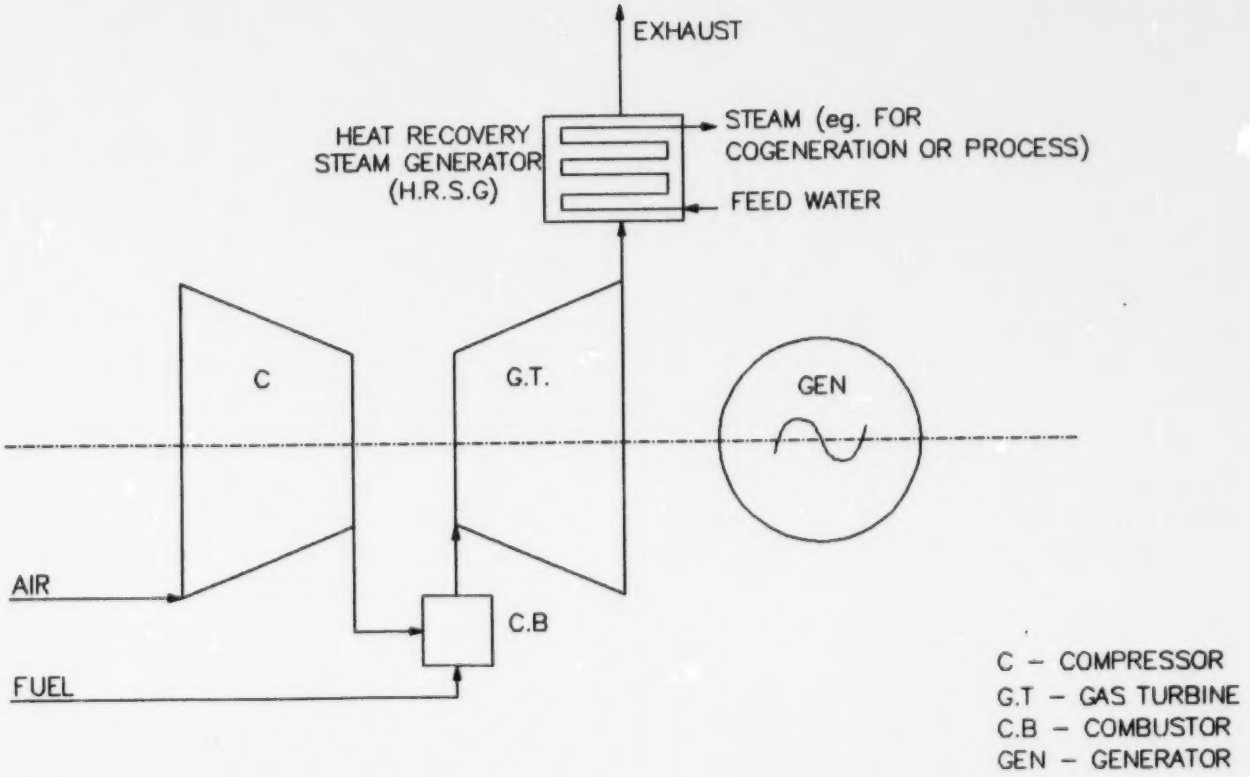


FIGURE 7-5. Simple cycle gas turbine plus heat recovery

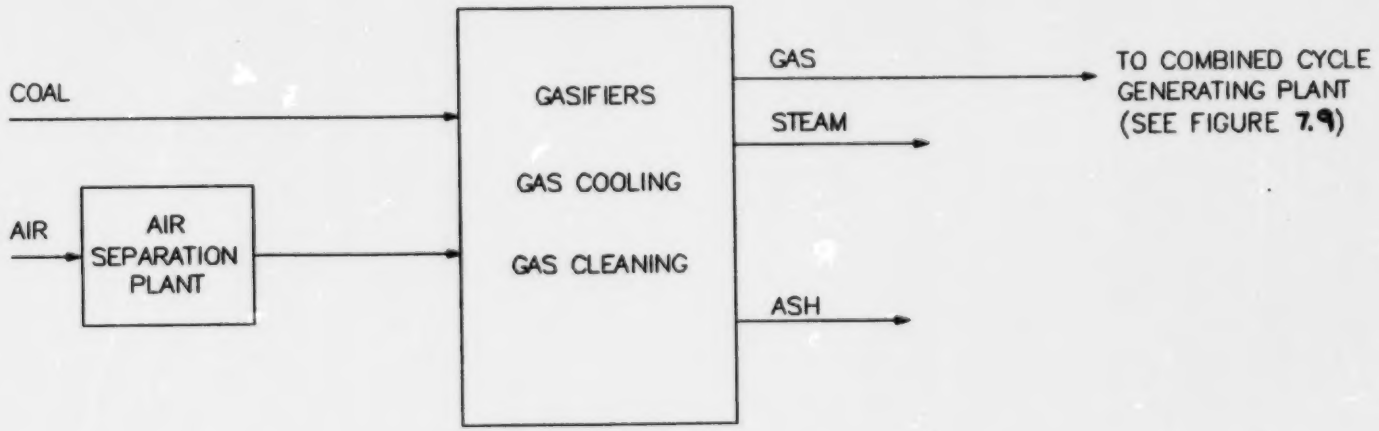


FIGURE 7-6. Integrated gasifier combined cycle

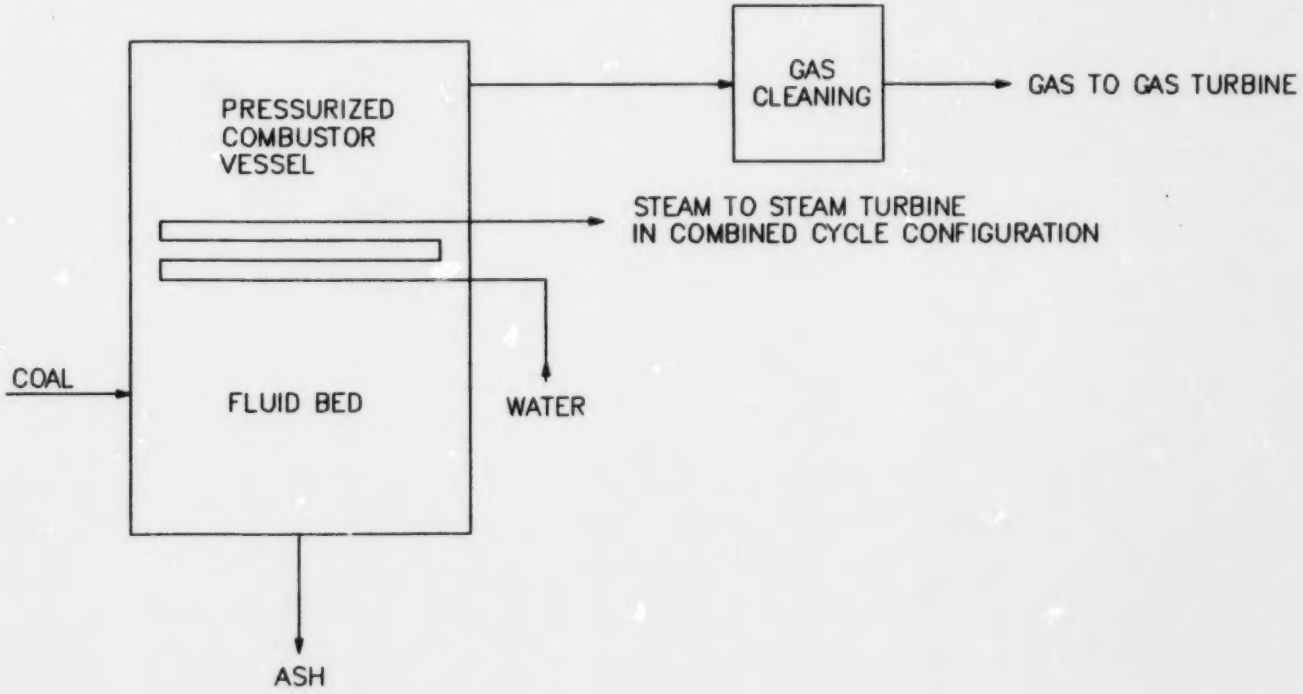


FIGURE 7-7. Pressured fluid bed combustion (PFBC)

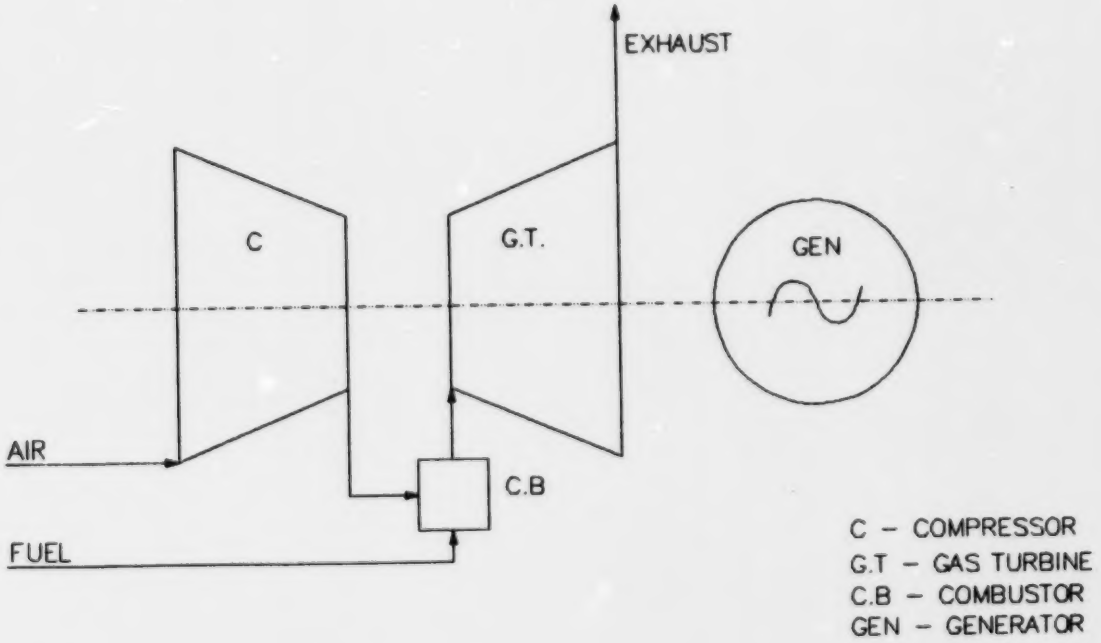


FIGURE 7-8 Simple cycle gas turbine

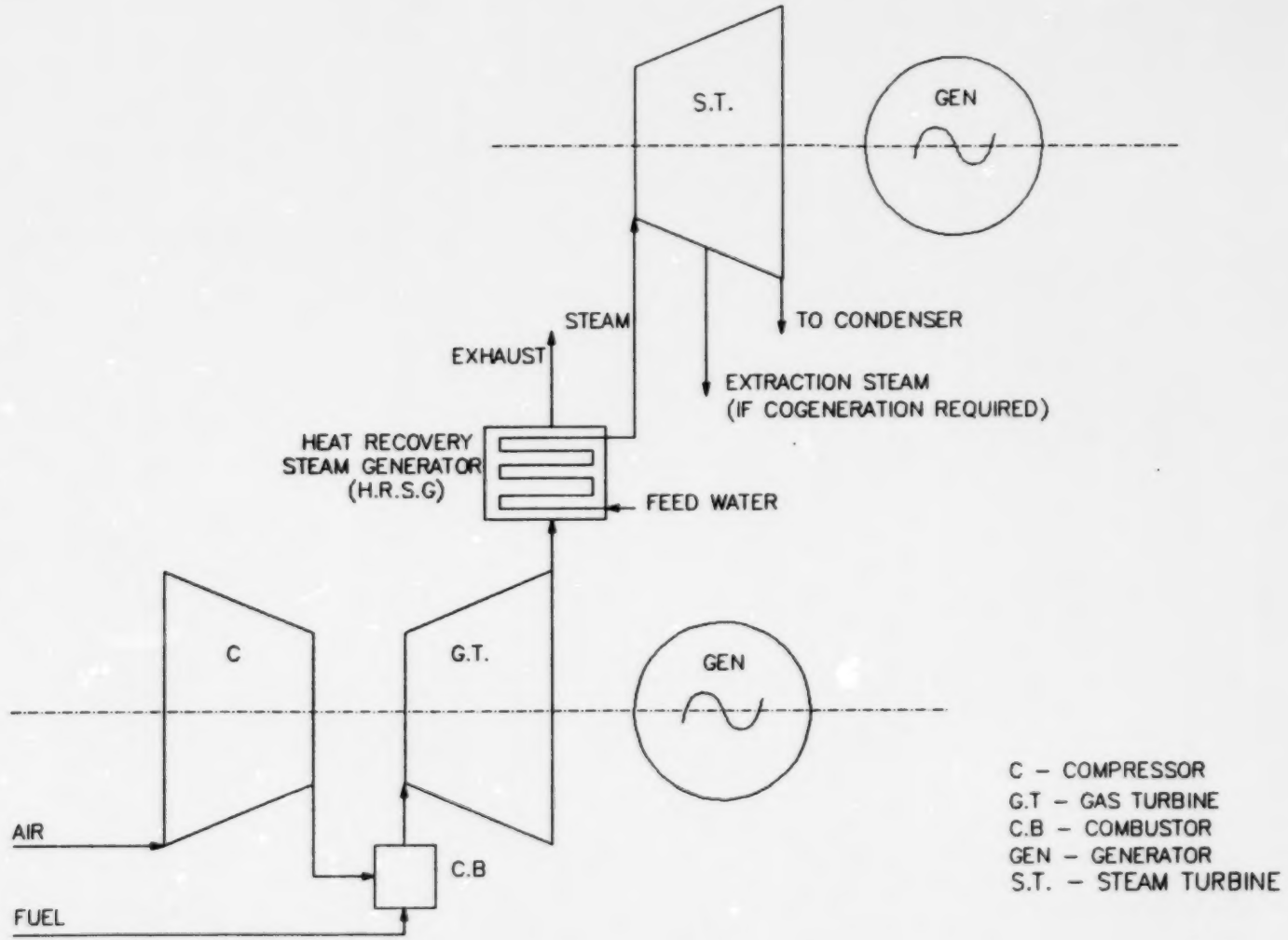
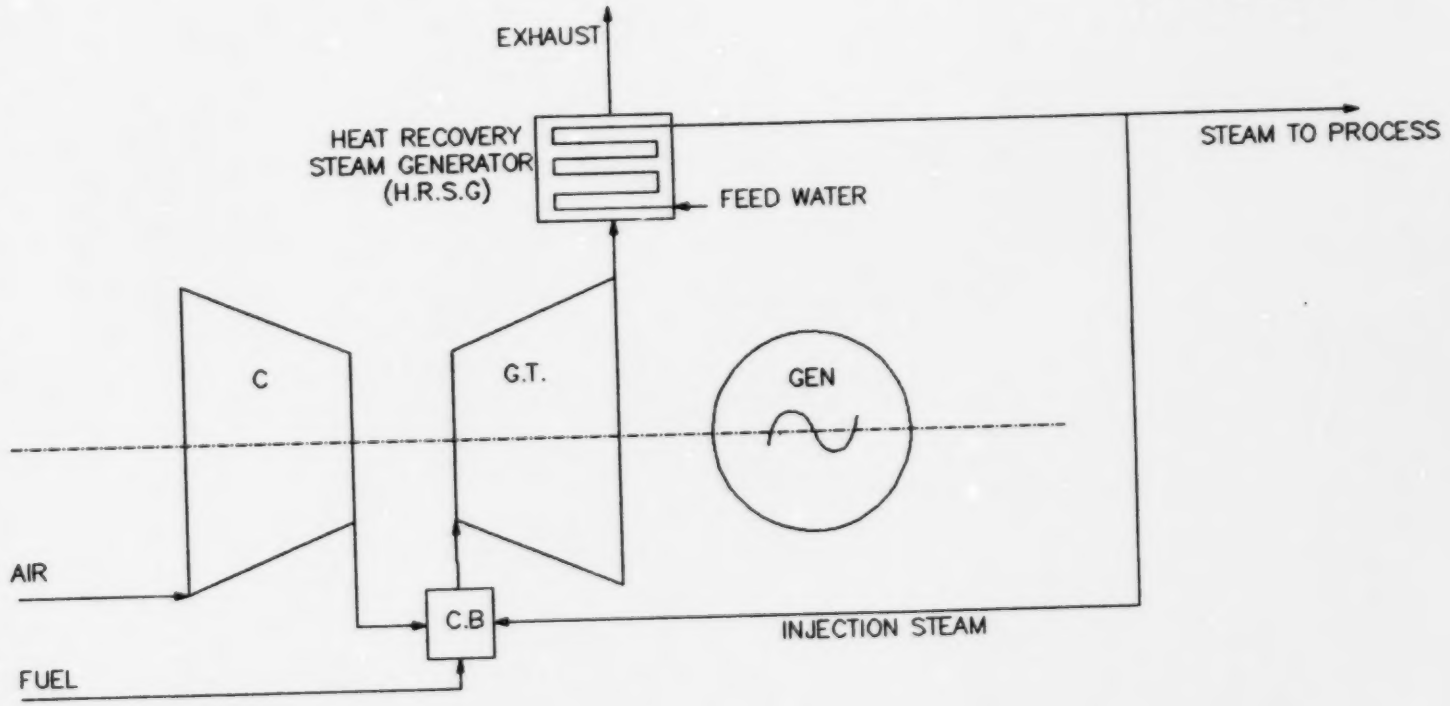


FIGURE 7-9. Gas turbine combined cycle

C – COMPRESSOR
G.T – GAS TURBINE
C.B – COMBUSTOR
GEN – GENERATOR



NOTE: I.S.T.I.G. CONFIGURATION IS AS FOR S.T.I.G. WITH INTERSTAGE COOLING OF AIR BETWEEN COMPRESSOR STAGES.

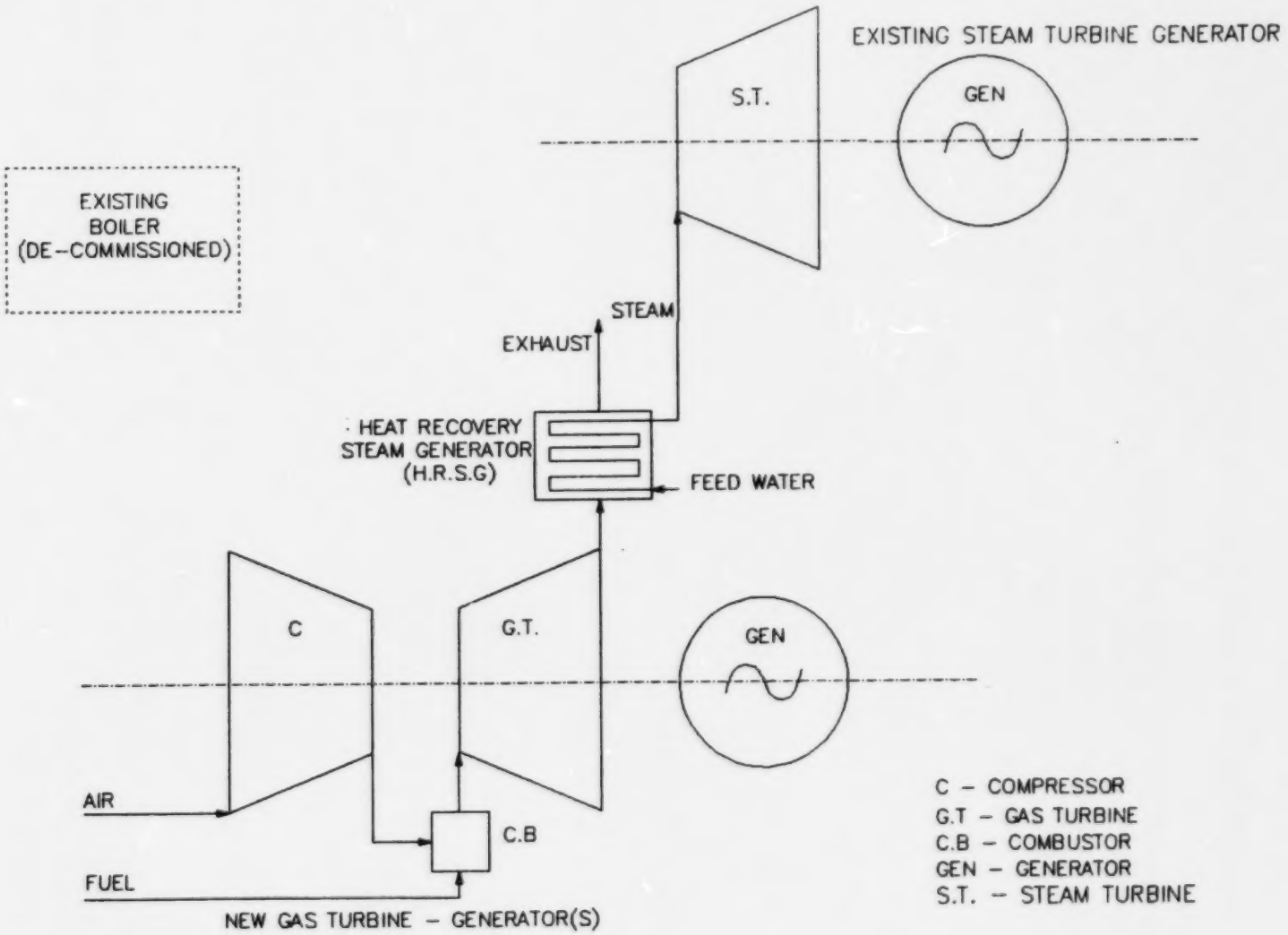


FIGURE 7-11. Repowering existing steam turbine

7.2 Non-Fossil Based Generation Technologies Available to 2005

7.2.1 Hydroelectricity, Tidal Energy and Nuclear Fission

Hydroelectric and tidal power are renewable energy resources, reviewed in Appendix A7-1. Capacity additions are restricted by lack of sites, economic, environmental, or technical reasons. Hydroelectric units provide about two-thirds of Canadian electric power, and are preferred base load options.

The 20 MW tidal power plant in Nova Scotia is the first of its kind in North America, and the largest installation in the world is only 240 MW. Economics and technical difficulties are often unattractive.

Wave power devices are potentially of utility capacity, but the largest experimental facility in operation is only about 500 kW.

The CANDU 3 reactor (roughly 450 MW) has a low lead time compared to a standard nuclear plant. Multi-unit stations will require longer. Point Lepreau in New Brunswick will be the first commercial unit, if it proceeds.

7.2.2 Other Technologies

Generating technologies based on biomass, wind or geothermal energy are reviewed in Appendix A7-3. They have found limited application elsewhere in North America, but have only low potential for large scale utility operations in Canada.

Solar power technologies are reviewed in Appendix A7-10, and Appendix A7-8 discusses energy efficiency and demand-side management. Photovoltaic (PV) electricity generation has progressed at a rapid rate during the past decade, with costs falling and module efficiencies improving greatly. Solar PV electricity could cost as little as 5-8 cents per kWh in Southern Canada by 2000-2010. Hybridizing PV power capacity with high efficiency fossil fuel backup capacity could reduce CO_2 emissions by about 18% compared to producing the same amount of energy purely from fossil fuels.

7.3 Longer Term Generating Technologies

The main longer term generating technologies are reviewed in the Appendices to Section 7. These are:

- Standard Nuclear Fission;
- Nuclear Fusion;
- Magnetohydrodynamics; and
- Molten Carbonate and Other Fuel Cells.

Standard CANDU nuclear reactors in the 550 MW (Pickering) to 900 MW capacity (Darlington size) range require long lead times. Over 400 nuclear units are in operation around the world, and the safety record of the CANDU systems is exemplary. Ontario Hydro's Demand/Supply plan proposes two new 3,524 MW CANDU nuclear stations, to enter service in the period 2003 to 2009. The nuclear option is controversial, however, and is only considered to be of borderline availability to other utilities for in service dates prior to 2005.

Nuclear fusion and magnetohydrodynamic (MHD) technologies offer CO_2 emission reductions. Both are longer term options, although gas-fired MHD units could be demonstrated in the USSR in the 1990's. Molten carbonate, solid polymer and other fuel cells are also promising technologies (see Appendix A7-4).

7.4 CO_2 Recovery and Disposal

CO_2 recovery from power plants can be accomplished using an absorption and stripping process now applied in other industries, or by designing coal "CO_2 boiler" units to produce a high purity CO_2 flue gas. Recovery of CO_2 requires additional energy and CO_2 usage or disposal must prevent subsequent release to the atmosphere. IGCC and modified conventional units recover CO_2 at less expense, but disposal considerations remain.

Disposal of CO_2 appears economically unattractive, except through local applications such as enhanced oil recovery (EOR). There is some potential in

Alberta and Saskatchewan for at least partial disposal of CO_2 through EOR and similar operations. Storage of CO_2 in oil or gas wells (apart from through EOR), salt caverns or ocean disposal (deep or shallow) do not appear at first pass to be economically feasible options.

A technical review of CO_2 recovery, usage and disposal options is given in Appendices A7-5 and A7-6.

7.5 Energy storage

Energy storage options, reviewed in Appendix A7-9, can be used in conjunction with non-fossil based generation to meet peak demand, possibly reducing the need for fossil-fuel based peaking capacity. Pumping water to reservoirs is a common approach; storage as compressed air or in batteries are less attractive options.

It is expected that technologies to use hydrogen to store energy will become commercially available as we enter the "Hydrogen Era". Utility scale storage coils may also become possible in the long term, in the light of recent laboratory breakthroughs in high-temperature superconductivity.

7.6 Steel Industry Technologies

Steel and cement industry technology trends are reviewed in Appendix A7-9. Emissions of CO_2 from industrial sources are given in Section 6.5. Emissions from steel industry sources, located mainly in Ontario, are significantly higher than from other coal-burning industries.

Technologies that offer reduced CO_2 emissions are the direct reduction of iron oxide pellets by the Midrex process, and the cokeless cupola.

The Midrex process produces only 0.5 tonnes of CO_2 per tonne of iron, in contrast to a conventional blast furnace operation which produces about 1.6 tonnes of CO_2 per tonne of iron. Two furnaces with an annual production

capacity of 1.1 Mt steel per year have been operated by Sidbec-Dosco for over a decade. Many other furnaces are in operation around the world.

Some 14 cokeless cupolas are in operation around the world. The technology has not, however, been widely accepted by North American foundries. Enviromelt operates a small experimental facility in Ontario. Emission rates of CO_2 are typically 0.1 to 0.15 t CO_2 per tonne of iron (Richard Taft, Enviromelt, Pers. Comm., February 1990). By contrast, a coke cupola produces 0.33 - 0.51 tonnes CO_2 per tonne of iron, depending on the furnace efficiency.

Both processes use natural gas, which offers fuel handling advantages over coal. Concerns over the reliability of gas supply and pricing are likely to constrain adoption of these technologies, however.

About 70% of North American steel production is still based upon the Coke Oven - Blast Furnace - Basic Oxygen Furnace process sequence of the integrated producer. Mainly gas-fired reheating furnaces are used in the integrated process. There is a trend towards the use of more oxygen and oil firing in the Electric Arc Furnace, which can decrease electrical usage by about 75 kWh/tonne, but is partly offset by the power needed to produce O_2.

7.7 Comparative Cost Assessment

Capital and electricity production costs of some of the main technology/fuel options to utilities are shown on Table 7-2, derived largely from information presented in Johanssen et al. (1989). This table should be read with due attention to the qualifying notes, especially those relating to coal and gas costs.

The table shows comparative costs. These should not be used to evaluate options without first defining data specific to Canada, especially fuel costs. Actual costs will also be greatly affected by site-specific factors, including:

- Coal mining methods;
- Coal characteristics and costs (EPRI CS-4283, 1986);
- Size and type of unit, operating mode and capacity factor;
- Conformity with existing plant layout;
- Acid gas emission reductions required;
- Timing; and
- Interest rates, inflation, economics.

The coal-steam option on Table 7-2 includes FGD. Capital costs of complete wet FGD systems in US$ 1988 are reported in the range of $200/kW to $280/kW (e.g. Ontario Hydro "Flue Gas Desulphurization Program - Study Summary").

The capital cost of IGCC is raised by the air separation and gasification plants which are integral parts of the overall power plant. The investment in IGCC can be staged, however, with only a modest cost needed for an initial stage involving the gas turbine alone (EPRI AP-5466-SR, 1987). The most costly investment, the coal gasification plant, can be added when economic and other factors allow.

Production costs for IGCC are relatively high due to the capital component, but coal costs are lower due to the higher efficiency. The size of a completed IGCC facility will have a significant effect on unit capital and production costs.

Table 7-3 shows a brief assessment of changes in production cost which result from changing from a coal-steam unit without FGD (base case) to options which emit less CO_2 per kWh. This table is based upon the data in Table 7-2, but is adjusted for a base without FGD. The gas-based options offer significant reductions in operating costs per tonne of CO_2 avoided. Changing to coal-IGCC significantly increases operating costs per tonne of CO_2 reduced.

Comparative PFBC capital and production costs are not shown in the reference for Table 7-2, but a separate comparison is shown in the notes to the table.

Capital costs for the advanced simple or combined cycle gas turbine units are only 30% to 40% of those for a new coal/steam conventional plant. Production costs are about 60% of those for coal/steam, but are highly dependent on the price of gas. Most existing gas turbines are simple cycle units used for peaking or "black start" purposes, and economics change when intermediate or base load becomes the mode of operation.

Cogeneration costs are evaluated by the industry concerned for the specific application involved, and vary with fuel availability, plant size, type and other operational factors. A key consideration is the price the local utility will pay the industry for electricity delivered to the regional system. Capital and operating costs for power generation in a cogeneration plant are generally, however, much lower than those for a normal power plant.

Cheap waste fuels may be available, for example bark in a pulp mill or waste coal in a coal washing plant. Cogeneration can then become very economically attractive. Also, since cogeneration plants are built and operated by the industry concerned, excess electricity can be sold to the local utility, providing additional economic incentive for the cogeneration process.

Total coal unit production costs are relatively high compared to any gas option. Fuel cost is the key component of the production cost in most cases. Operation and maintenance costs are much lower for gas options. Basic trends, directions, uncertainties and interpretation of fuel forecasts are reviewed in EPRI AP-5711 (1988). This study concludes that current events and historical trends can provide guidance on near-term (1 to 3 years) fuel purchase decisions, but that history has proven that it is impossible to forecast the more distant future with any degree of accuracy. Coal prices tend however, to fluctuate less than the price of other fossil fuels.

Utilities do not at present include costs related to CO_2 reduction in their evaluation of fossil fuel generation options. In addition to normal capital and operating cost considerations, the costs of options to meet acid rain and other emission limits predominate in present evaluations.

TABLE 7-2: CAPITAL AND OPERATING COSTS - COMPARISON (see notes)

TECHNOLOGY		COAL-STEAM with FGD	GAS-STEAM	GAS TURBINES			COAL - I.G.C.C.	
				ADVANCED COMBINED CYCLE	S.T.I.G.	I.S.T.I.G.		
Unit size	MW	2 x 500	2 x 500	1 x 205	4 x 51	1 x 114	1 x 250	1 x 600
Inlet temperature	°C	540/540	540/540	1260	1200	1370	1090	1200
Efficiency	%	34.6	36.3	45.0	40.0	47.0	35.7	37.9
Capital Cost (1987 US$)	$/kW	1340	760	520	410	400	2000	1550
Capital Cost Comparison		Base(1.00)	0.57	0.39	0.31	0.30	1.49	1.16
Production Cost (Levelized Busbar) (1987 US cents/kWh)								
Capital		1.61	0.90	0.63	0.49	0.48	2.39	1.85
Fuel		1.86	2.08	1.68	1.89	1.61	1.81	1.70
Operating & Maint.		0.89	0.49	0.29	0.29	0.29	1.19	0.80
Total		4.36	3.48	2.60	2.67	2.38	5.39	4.35
Production Cost Comparison		Base(1.00)	0.80	0.60	0.61	0.55	1.24	1.00

Notes to Table 7-2

1. Cost data extracted from Table 2 p524 of "Electricity", Editors: Johansson, Bodlund and Williams, Lund University Press, Sweden 1989

2. All costs are 1987 US $.

3. Data for the coal-steam units are EPRI estimates for bituminous coal sub-critical units with FGD.

4. The assumed coal price is US $1.79/GJ. This is the average US utility price projected for year 2000 by the US Dept. of Energy. Prices in Canada may differ (e.g. Western Canadian coal will likely be less)

5. Efficiencies are based on fuel HHV and for operation at 100% load.

6. Levelized busbar capital costs are based upon a 6.1% real discount rate, a 30-year plant life, and a 70% capacity factor. No taxes or tax incentives are included.

7. The Advanced Combined Cycle unit is a 135 MW gas turbine with 70 MW steam turbine.

8. Estimates of costs by suppliers and consultants are used in addition to those of EPRI.

9. Average gas price for US electric utilities was US $2.10/GJ in 1987. Prices in Canada may be less.

10. Published data by Shell and Texaco on their coal-IGCC systems for comparison with the last two columns of Table 8-2 are:

		Shell	Texaco
Unit size	MW	383	360
Inlet temp	°C	1260	1260
Efficiency	%	38.8	37.54
Capital Cost per kW		1470	1530

11. Cogeneration options not shown on this table.

12. IGCC capital costs and operating costs include costs for the Air Separation and Gasification Plants.

13. Table 7-2 does not give comparative costs for pressurized fluid bed combustion (PFBC). However, Table 7 on p. 584 of the same reference text gives the following data from "Proceedings of Conference on Comparative Economics of Clean Coal Technologies", Grand Junction, Colorado, 1987.

The below data are not directly comparable with those on Table 7-2.

Plant capacity — 680 MW, capacity factor 65%
Capital carrying charge 17.8%

	COAL-STEAM WITH FGD	PFBC
Efficiency %	36.6	40.8
Capital cost/kW (US$ 1987)	1350	1310
Production Cost (cents/kWh)		
Capital	5.51	5.07
Coal	0.93	0.84
O&M	1.51	1.60
	7.95	7.51

TABLE 7-3: CHANGE IN PRODUCTION COST PER TONNE OF CO_2 EMISSION REDUCED

TECHNOLOGY CHANGE	COMPARATIVE PRODUCTION COST[1]	CO_2 EMISSION RATE (FULL CYCLE)	COST PER TONNE OF CO_2 EMISSION REDUCTION[2]	
	1987 US¢/kWh	kg CO_2/kWh	1987 US$	1988 C$
Base - Bit., coal-steam without FGD	3.93	1.06	--	--
Base to gas steam	3.48	0.60	- 9.8	-12.0
Base to gas turbine adv. comb. cycle	2.60	0.52	-24.6	-30.2
Base to Bit. coal - IGCC @39% eff.	4.30	0.92	-26.4	+32.4
Base - [3] Conversion coal to gas-steam	2.63	0.60	-28.3	-34.7

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(1) Levelized.

(2) 1987 US$ x 1.18 x 1.04 = 1988 C$.

(3) Assuming US (1987) $30/kW capital cost for gas conversion.

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8.0 LEGISLATIVE SCENARIOS AND PLANNING OPTIONS

8.1 Scenarios of CO_2 Emission Reduction

Two scenarios of legislative action to reduce anthropogenic CO_2 emissions are considered. Scenario I corresponds to the call to action of the June 1988 Toronto Conference:

Scenario I: Reduce CO_2 emissions by 20% of 1988 levels by 2005; and
Scenario II: Hold CO_2 emissions to the 1988 base level by 2005.

8.1.1 Application to Canadian CO_2 Emissions

If action is driven by an international protocol, rather than by unilateral action, then Canada will be required to meet a national CO_2 emission limit.

Applying the scenarios to total Canadian CO_2 direct combustion emissions, the required reductions from all provinces and sectors would be approximately:

Source	Projected 2005 CO_2 emission (Mt)	---- Reductions (Mt) ---- Scenario I	Scenario II
NEB (low)	598	220	125
NEB (high)	649	271	176
EMR	706	328	233

where Canadian CO_2 emissions from all sources in 1988 are estimated to have been 473 Mt (Task Force, 1989). Projections of national CO_2 emissions in 2005 are discussed in Section 6.4.

8.1.2 Application to Utility Full Cycle CO_2 Emissions

Applying the scenarios to electric utility full fuel cycle emissions only, the required CO_2 cuts from present projections of 2005 emissions (Mt) are:

	Utility CO_2 Emissions		--------Reductions--------	
	1988	2005	Scenario I	Scenario II
Ontario	39.1	39.1*	7.8	0.0
Alberta	47.5	74.0	36.0	26.5
N.S.	8.5	15.1	8.3	6.6
N.B.	7.7	15.2	9.0	7.5
Saskatchewan	14.1	19.7	8.4	5.6
Others	5.0	12.7	8.7	7.7
	121.9	175.8	78.2	53.9

* An additional 10.7 Mt of CO_2 is estimated from a preliminary assessment of Ontario Hydro's Demand/Supply plan.

8.2 Impact of Scenarios

Scheduling of the legislative scenarios is an important consideration. Industries and communities can better deal with change if given longer to react. Coal industry and electric utility operations and projects are often capital intensive; they are characterized by long planning periods and considerable economic inertia.

Canadian Electric Utilities and Coal

The electric utilities and coal industry in many Canadian provinces have a close economic symbiosis. The continued use of coal is critically important to several utilities as they plan to meet future increases in electrical energy demand. Conversely, local electricity generation constitutes the only market for thermal coals in many areas. Utilities in Western Canada, for example, use mainly low quality local coals with high ash and low moisture content. Thus a decrease in coal reliance in, say, Alberta would greatly affect provincial coal mining communities since three-quarters of Albertan coal production is for local power plants.

Legislative action to reduce CO_2 emissions from Maritime utilities would probably reduce local coal production in Nova Scotia and New Brunswick. This would be particularly likely at mines serving power stations with lower efficiencies and without SO_2 reduction facilities. Opportunities to sell coal from Western Canada to the Maritimes may emerge, however.

If the ability of electric utilities to meet peak electricity demand periods is reduced by CO_2-related legislative action, then periods of brown-outs and possibly even black-outs might result.

There would be reduced coal usage in regions where "clean" power is purchased by utilities or added in the form of, say, hydroelectric power; or where energy conservation measures reduce demand for coal-based power generation.

Electric utilities in British Columbia, Québec, Manitoba and Newfoundland use mainly hydroelectric stations to generate electricity, and similarly plan to meet future increases in electricity demand largely through "clean" power. However, other economic sectors within these provinces contribute to Canadian CO_2 emissions as a whole, in some cases significantly (see section 6.4).

If all sectors of a provincial economy are required to reduce CO_2 emissions, there may be a partial transfer of responsibility for net CO_2 emission reductions to utilities. An example would be a trend in, say, the manufacturing sector to switch from oil/gas boilers to electric boilers.

The Coal Industry

The Canadian coal industry is internationally competitive and capital intensive, with an annual revenue in excess of $2 billion in 1988. It provides direct work for some 12,000 people and indirectly for many more. Although the majority of mines are in Western Canada, mines in the Maritimes are key components of their provincial economies. Coal industry support workers, for example those in the transportation sector, would also be impacted by legislative action directed at the coal industry.

A decrease of thermal and metallurgical coal reliance in Ontario would primarily affect USA suppliers. About 17 Mt of bituminous coal was imported in 1988, although about 5 Mt thermal coal was shipped from Western Canada.

There would be reduced coal usage in regions where natural gas is selected. Greater competition between coal and natural gas on a point-of-delivery basis can be foreseen.

Renewed demand for further conservation measures and efficiency in coal mining, preparation, shipping and handling can be expected. Calls for improved coal quality and for minimization of CO_2 and CH_4 emissions from coal processing operations can be expected. It should, however, be noted that the coal industry is already considered to be lean and competitive, following the market downturn of 1986.

Clean coal technologies are being developed in response to environmental issues such as acid rain, not global warming (CIAB, 1985). Introduction of generating technologies which have higher efficiencies, such as IGCC and FBC, will mean less coal per kWh is required. But they will also allow coal to remain competitive as an energy source in the face of environmental concerns.

The Coal Export Market

Any legislative action by Japan or Pacific Rim countries that reduces their metallurgical coal imports will primarily impact mines in British Columbia and Alberta. Mines in British Columbia have a combined direct work force in excess of 5,000 and depend entirely on extra-provincial markets, primarily the metallurgical coal export market. Unilateral CO_2-related legislative action by Japan or by other Pacific nations is unlikely, however, due to the positions of the governments concerned (Section 4).

8.3 Planning Options

8.3.1 Discussion

The world cannot realistically meet future energy demand needs without using coal (see Section 5). Canada is fortunate to be able to meet two thirds of its electrical energy needs using "clean" hydroelectric power alone. Canadian coal reserves are large, however, and of great economic importance to Canada.

Canada has a recognized leadership role in addressing environmental concerns. It is clear, however, that even drastic unilateral action by Canada would have little effect on the build-up profile of atmospheric CO_2. This is not a recommendation to do nothing, but a recognition that an international and broad-based response is needed if the build-up is to be significantly slowed.

In general, reasonable measures to reduce potential impacts should be taken while attempts are made to reduce the scientific uncertainty. Key factors to consider in Canada are that:

- The use of thermal coal in Canada is regional. Alternative means of generating electricity are not readily available in many cases;

- The distribution of CO_2 emissions from different Canadian provinces and economic sectors varies greatly. A need for inter-provincial co-operation is indicated. Also, if all provinces are to contribute to an overall reduction of Canadian CO_2 emissions, then cuts must come from transportation and other non-utility sectors in addition to utilities; and

- There will come a point beyond which it is more cost effective to assist others in their efforts to reduce CO_2 emissions from fossil fuels than to further attempt to reduce Canadian emissions.

Electrical utilities are faced with the possibility of changing their future generating plans in the face of global warming concerns. These plans may or

may not include coal-based generating technologies. The coal industry, on the other hand, is faced with the challenge of developing technologies to ensure that coal remains competitive as an energy source.

8.3.2 General Options

In the light of the above discussion, several broad response options to reduce net global CO_2 emissions should be considered by utilities and, in some cases, by the coal industry. The aim of these options is to offset CO_2 emissions from Canadian sources by reducing CO_2 emissions elsewhere.

Some options can be viewed as business opportunities (see Wiggins 1989). For example, markets for coal gasification technology may emerge. Canada also has recognized excellence in hydroelectric and heavy water nuclear engineering.

Broad response options include:

Exporting Canadian Hydroelectric Power

Nearly 32 GWh of Canadian hydroelectric power was exported to the USA in 1988 (EMR, 1989). The USA is currently responsible for one fifth of global CO_2 emissions. There is potential for additional export of "clean" Canadian power, although government approvals must be gained as necessary.

Reforestation Projects

Applied Energy Services (AES) of Arlington, Virginia, has undertaken a reforestation/agroforestry project in Guatemala. The project is designed to offset CO_2 emissions from a 183 MW FBC, coal-fired power plant over its 40 year lifetime (Trexler et al. 1989). AES is seeking further projects to offset emissions from other planned units, and advocates levying a tax on fossil fuel use from which utilities would be exempt if they opted to provide offsetting CO_2 sinks somewhere in the world (The Energy Daily, 12 July 1989).

Technology Transfer

Technology transfer is probably the most cost-effective approach to reducing CO_2 emissions from industrializing countries such as China and India. It is clearly desirable that new or retrofit fossil based generation units use the most efficient technologies available.

There is also general recognition that involvement of many key nations in protocols addressing climatic change or other global environmental issues will require both financial and technical assistance from industrialized countries.

Demand-Side Options

Demand-side management, solar power, fuel cells, energy storage and energy efficient technologies can reduce the demand for utility coal-fired power generation. In some cases, regulatory intervention may be needed to establish markets. For example, the introduction of long-life low-power light bulbs.

The potential for demand-side energy savings is reported to be considerable and often economically attractive (DPA report to Task Force, 1989). Mintzer (1987) shows that a relatively small difference in the rate of improvement of end use energy efficiency can substantially reduce CO_2 emissions over a period of 50 to 75 years. Demand-side options are discussed further in the Appendices to Section 7.

Demand-side technology improvements can also be applied to mining operations. Supplying utility power to remote mines can be expensive. Using "cleaner" and energy efficient technologies could reduce the "life cycle" CO_2 emission mark-up factor for a given mine.

8.3.3 Fossil-Based Generating Options

The main fossil-based technology/fuel options presented in Section 7 for in-service dates to 2005 are:

- Conventional Steam (coal, oil, gas);
- Cogeneration;
- Integrated Gasification Combined Cycle (IGCC);
- Fluidized Bed Combustion (FBC); and
- Gas Turbines.

These options should be reviewed by planners in each region to determine how closely the utilities can approach the regulatory CO_2 emission scenarios.

An initial review was carried out for the main regions using fossil-fuel, and for Canadian utilities overall, as follows:

New Fossil Units

A list was developed of probable fossil units additions to 2005, based upon utility forecasts when available, and upon assumed additions where necessary (EMR, 1989; questionnaire responses). These units are divided on Table 8-1 into those already committed (5.7 GW), and those as yet uncommitted (3.0 GW).

First Approach to Scenarios

Regional and national CO_2 emissions in 2005 were estimated using assumed capacity factors and CO_2 emission rates per kWh (Table 7-1). Table 8-2 shows:

- The CO_2 emissions which can be expected in the absence of CO_2 concerns (176 Mt; see Section 6.4); and

- The CO_2 emissions which can be expected if fossil options that minimize CO_2 emission are selected for uncommitted units (170 Mt).

Table 8-3 compares these lower estimates of utility CO_2 emissions in 2005 with the legislative scenario limits. A preliminary assessment of Ontario

Hydro's Demand/Supply plan concludes that Ontario will likely be in excess of the scenarios by an additional 10.7 Mt.

It is clear that this realistic selection (there are others) of regional fuel and technology options for new units to be commissioned before 2005 does not closely approach the scenario limits.

Further Options to Approach Scenarios

The next fossil-related supply-side options to reduce CO_2 emissions are to:

- Convert either "committed" units (where possible) or existing units to lower CO_2 emitting fuels and/or technologies; and

- Retire older fossil units, replacing them with lower CO_2 emitting generating technologies/fuels.

Such measures would prove to be very expensive. As noted elsewhere, the need for them depends in part on politically decided factors, such as the timing of legislated CO_2 reduction limits, the willingness to compromise the ability of utilities in some regions to meet periods of peak demand.

Utilities in Alberta, Saskatchewan, New Brunswick and Nova Scotia would face the most difficult planning challenges if legislative action is implemented.

Final Approach to Scenarios

A rough assessment was made of the fossil fuel and technology measures that would be needed if legislative action was imposed on utilities on a region-by-region basis, regardless of practicality.

Scenario I (the 20% CO_2 emission reduction from 1988 levels) could be achieved by converting all the coal-fired and oil-fired power stations in Canada to gas-fired steam generators. It would also be necessary to substitute gas turbine/combined cycle units using natural gas for all the coal-fired unit additions planned for 1988 to 2005.

8.3.4 Non-Fossil Generating Options

"Clean" generating options available by 2005 for utility use include nuclear (CANDU 3) fission, hydroelectric and tidal units, and purchasing "clean" power from other utilities.

The CANDU 3 reactor is as yet untested, but New Brunswick is considering ordering the first such reactor for Point Lepreau. Hydroelectric power options are limited by site availability, economic and technical difficulties. Nevertheless, about 46 GW of hydroelectric planning potential remains across Canada, notably in Newfoundland, Manitoba and Québec. These provinces, however, are not among those who would face great difficulties in meeting CO_2-related legislative measures. Conversely, hydroelectric power is not an option for regions such as Alberta. Also, tidal sites are essentially limited to Nova Scotia.

Transfer of power between provinces in 1988 was about 49 GWh (EMR, 1989). This clearly provides an alternative to adding new capacity.

8.4 The North American Perspective

Canada's technology selection decisions will reflect those made by utilities and the coal industry in the USA. The United States plans significant growth in capacity and, with a nuclear industry on hold (no reactor has been ordered since 1978) and few hydroelectric opportunities remaining, is facing a much tougher CO_2 challenge.

The USA clean coal technology development programmes are at present directed mainly at controlling SO_2, NO_x and particulate emissions. The environmental impact of the US clean coal demonstration program is given in DOE (1989). A major conference entitled Coal in the Environment is planned by the World Coal Institute for 3-5 April, 1991, London, England. An overview of both clean coal technology advances and technical mitigation strategies for CO_2 is scheduled.

Fossil-fuel based generating capacities in 1988 for Canada and the U.S. were:

	Canada	U.S.A.
Coal	19	315
Oil	7	56
Gas	4	100
Total	30 GW	471 GW

8.5 Research and Development Recommendations

Canadian Electrical Association and Coal Industry R & D of technologies and fuels to reduce CO_2 emissions should focus on:

- Determining the suitability of Western Canadian sub-bit. coals and lignite for gasification, including coal preparation and sizing;
- Pilot plant demonstration of IGCC gasification and FBC processes in key coal areas;
- Including CO_2 emission evaluation in research and development work relating to other emission (SO_2, NO_x) limits;
- Collaborating with industry and others to identify major Canadian cogeneration opportunities. District heating applications (using coal where feasible) should be considered;
- Monitoring USA clean coal work, sharing in appropriate R & D programmes;
- Pilot plant demonstration of a natural gas phosphoric acid fuel cell process;
- Improving molten carbonate, solid polymer and other fuel cells; and
- Continued efforts to increase efficiency in all areas (specifics

are not addressed by this study) of coal supply and utilization, and of electricity production, transmission and distribution.

In the long term, development of nuclear fusion and of superconductivity is important. Funding and work in these areas is already considerable, however. Coal-based magnetohydrodynamics (MHD) has only low research priority, but the potential of gas-fired MHD should be periodically re-assessed.

Continued research into solar power and other small-scale electricity generating technologies is recommended. Applications for these technologies also need to be developed. CEA should also consider investing in R & D work leading towards the "Hydrogen Era" (e.g. H_2 as an energy storage medium).

Further specific recommendations relating to flue gas emission controls and clean coal technology R & D are given by CEA (1989). This study considers overall R & D needs in these areas, rather than those relating to CO_2 alone.

Assessing the economics of CO_2 recovery and use/disposal options should focus on application to IGCC and on local disposal opportunities, such as Enhanced Oil Recovery in Alberta and Saskatchewan. This is not, however, recommended as an R & D priority.

There is also a pressing need for more research on climatic change. Studying climatic change with General Circulation Models requires supercomputers. However, there is also a need for a range of studies which do not require such expensive tools. For example, the development of study methodologies; assessment of possible regional impacts if a warming is assumed; and developing a better understanding and better models of mesoscale aspects of large-scale climatic changes. Potential impacts on utility planning and operations should be re-assessed periodically.

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TABLE 8-1: PROBABLE FOSSIL UNIT CAPACITY ADDITIONS (MW) TO 2005

		COMMITTED	UNCOMMITTED	TOTAL
NOVA SCOTIA	Coal	300	646	946
NEW BRUNSWICK	Coal	600	560	1,160
	Oil (G.T.)	30		30 (Oil)
(G.T. is Gas Turbine)				
ONTARIO		--	--	--
SASK.	Lignite	300	300	600
	Gas (G.T.)	150		150 (Gas)
ALTA.	S.B. Coal	1,180	1,486	2,666
	Gas (G.T.)	1,500		1,500 (Gas)
OTHERS	Oil	944		944 (Oil)
	Gas (G.T.)	662		662 (Gas)
CANADA	Coal	2,380	2,992	5,372
	Oil (G.T.)	974		974 (Oil)
	Gas (G.T.)	2,312		2,312 (Gas)
	Total	**5,666**	**2,992**	**8,658**

Notes: Ontario Hydro data, received after this table was prepared, shows the following proposed fossil unit additions:

- 672 MW Simple gas turbines (peaking) by 1993
- 672 MW Simple gas turbines (peaking) by 1994
- 1008 MW Gas turbine combined cycle, possibly by 2001
- 2016 MW Coal-IGCC (in phases), possibly by 1997

Ontario Hydro also expect Industrial Non Utility Generation (NUG) cogeneration to increase.

British Columbia has recently announced some private power projects, including coal-fired cogeneration and gas turbine combined cycle options. These are not included under "others" in this table.

TABLE 8-2: ESTIMATED FULL CYCLE UTILITY CO_2 EMISSIONS IN 2005 (Mt PER YEAR)

	CO_2 IN 1988	CO_2 FROM ADDITIONS			CO_2 IN 2005	
		COMMITTED	UNCOMMITTED			
			(1)	(2)	(1)	(2)
N.S.	8.5	2.08	4.48	4.37	15.05	14.94
N.B.	7.7	3.97	3.54	3.46	15.16	15.08
ONT.	39.1	--	--	--	39.13	39.13
SASK.	14.1	3.09	2.54	1.01	19.68	18.15
ALTA.	47.5	14.45	12.03	7.98	73.99	69.94
OTHERS	5.0	7.78	--	--	12.73	12.73
CANADA	**121.9**	**31.37**	**22.59**	**16.82**	**175.74**	**169.97**

(1) With uncommitted additions as presently envisaged.

(2) With uncommitted additions using "minimum CO_2" selections.

TABLE 8-3: ESTIMATED 2005 EMISSIONS V SCENARIO LEVELS (Mt CO_2/YR)

	SCENARIO LIMITS		ESTIMATED 2005 EMISSION[3]	EXCESS OVER SCENARIO	
	I[1]	II[2]		I	II
N.S.	6.8	8.5	14.9	8.1	6.4
N.B.	6.1	7.7	15.1	9.0	7.4
ONT.[4]	31.3	39.1	39.1	7.8	0
SASK.	11.2	14.1	18.2	7.0	4.1
ALTA.	38.0	47.5	69.9	31.9	22.4
OTHERS	--	--	12.7	--	--
CANADA	97.4	121.9	170.0	72.6	48.1

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[1] 1988 Emission levels less 20%.

[2] 1988 Emission levels.

[3] Using the lower estimates from Table 8.2.

[4] With no fossil fuel additions 1988-2005 in Ontario. A preliminary assessment of Ontario Hydro's 25 year Demand/Supply plan concludes, however, that planned fossil additions would result in an additional 10.7 Mt of CO_2 per year by 2005.